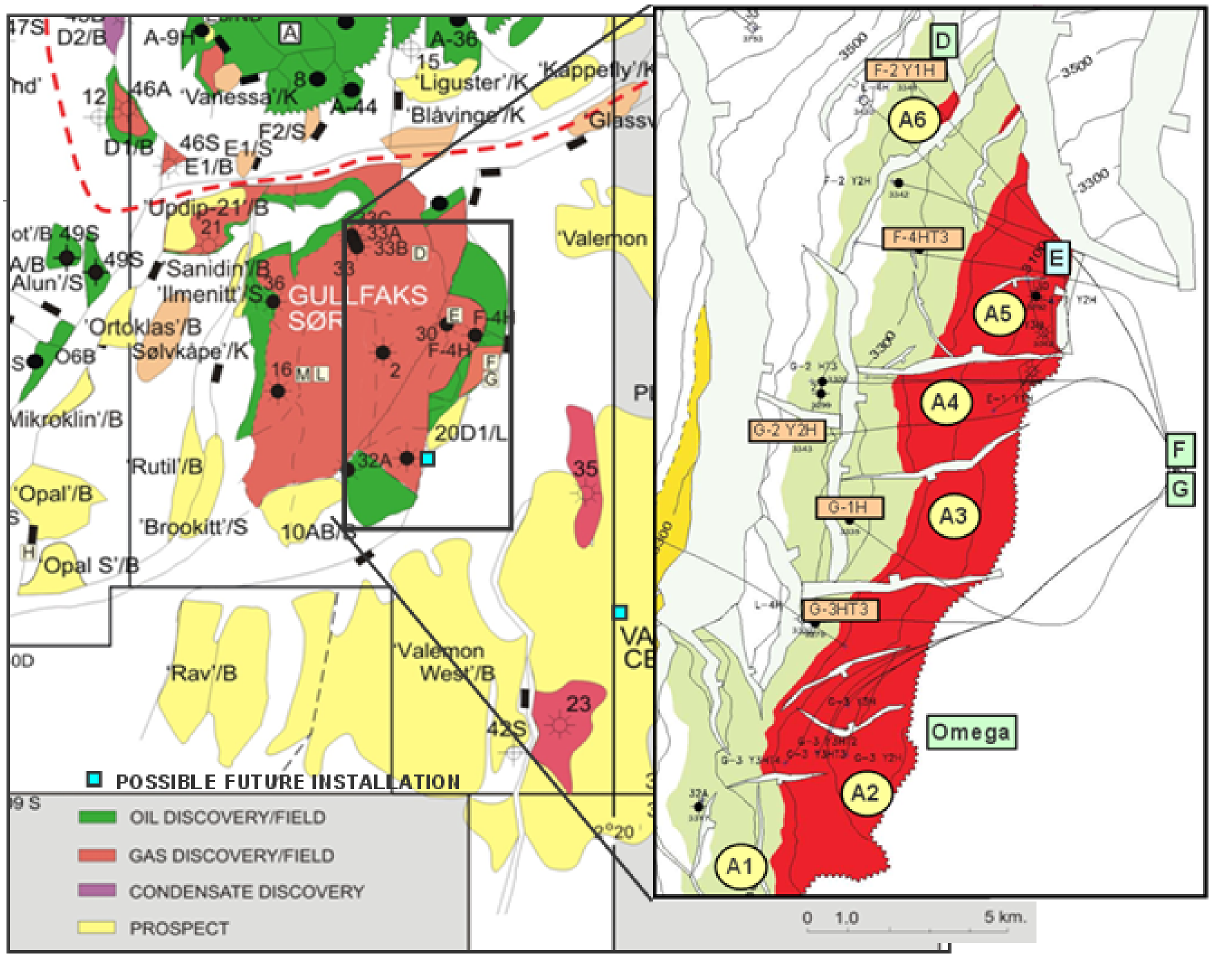
GullfaksVillage 2010. Part A



Group 1

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1. Overview of project and Gullfaks Sør

1.1 Project Overview

Deliver the expected results of part A in “Gullfaks Village” project, is the purpose of this report which have been done by Group 1. The main tasks are listed below:

1. The history matched Gullfaks Sør Statfjord Fm. model is provided with Statoil’s history matched Reference case for the field. All students should be familiar with this model and each group should run the model, and plot and review relevant reservoir results.
2. A new reservoir simulation run shall be made by adding four new oil producers and two new gas injectors to the model. Three of the producers are Multi-Lateral (MLT) wells. The coordinates for the wells will be provided by Statoil. This case should be termed the “Extended case” and it shall be compared with the “Reference case”.
3. Make an economic evaluation if the additional oil recovery from the “Extended case” can be part of a reserve potential for a new drilling platform at Gullfaks Sør, or if a subsea alternative provides a better solution. Cost data and other economic assumptions should be assumed by each group.

The results and the main info about Gullfaks Sør are given discussed in following sections.

1.2 Gullfaks Sør Geological history

1.2.1 Introduction

The Gullfaks satellites include 3 fields, Gullfaks Sør, Rimfaks and Gullveig. Both Gullfaks and the Gullfaks satellites are mainly located in block 34/10 on the west-flank of the vikinggraben. Vikinggraben is a result of an extension regime within the northern North Sea basin. The northern North Sea is limited by the Norwegian mainland in east and the Shetland platform in the west, stretching from approx 58 degrees to 62 degrees N.

The next chapters will give the reader a short briefing on the structural and sedimentological history of the northern North Sea basin and the vikinggraben.

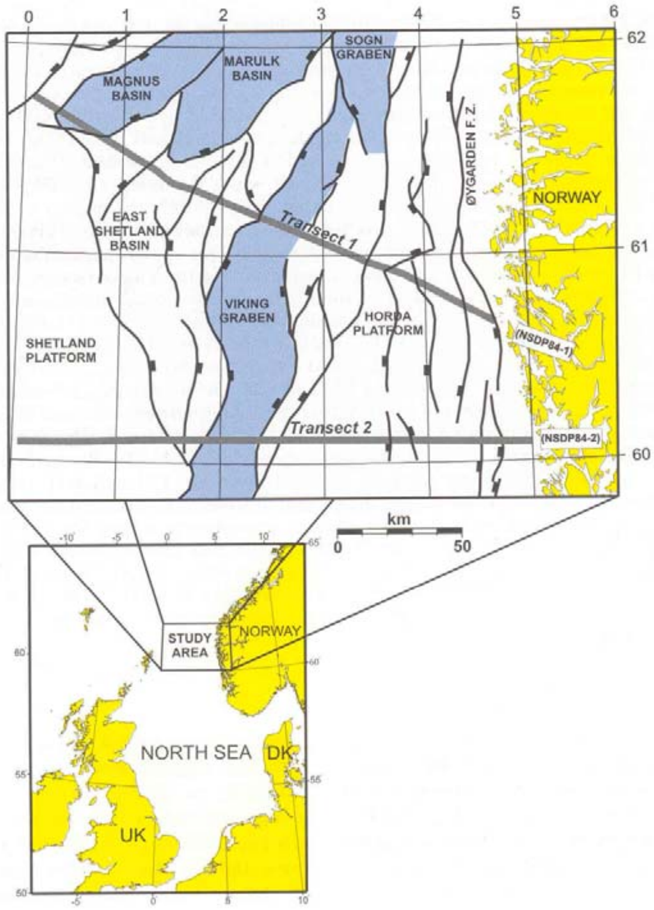


Figure 1.1. Vikinggraben and the surrounding structures. Grey areas are those affected by the rifting during Jurassic. From Odinsen et al. (2000).

1.2.2 Vikinggraben structural history:

We have considered the Permian – Triassic and the Jurassic to be the most interesting geological periods regarding the formation of the Vikinggraben.

In Permian the western and central parts of Europe were a part of Pangea. During the transition between late Permian – early Triassic there was a shift from compression to extension, which resulted in a rift phase. Pangea started to crack, and in the northern North Sea the extension created huge tilted fault blocks limited by N-S trending fault zones. By the exit of Triassic there were created a 140-150 km wide basin in this area.

During middle Jurassic until lower Cretaceous the area went through another phase of rifting. This rifting resulted in new N-S- and NNE-SSW-going listric faults and even higher subsidence of the basin floor. Vikinggraben is “an arm” in such a Jurassic rift system. The triple riftsystem consists of Vikinggraben, Sentralgraben and the Moray Firth Basin. Together with Sogngraben the system represents the area with the maximal extensions in the northern North Sea in the Jurassic. In the late Jurassic (kimmeridge-volg) a NE-SV trending fault regime is cutting the old N-S- zones creating a section of smaller, rhomboid fault blocks. The geometry of the faulting resulted in a rotation of the fault blocks towards the basins center.

In Cretaceous and tertiary the extension rate is falling and there is a subsidence due to thermal cooling and sediment loading.

1.2.3 Vikinggraben sedimentological history:

In our assignment we were told to focus on the Statfjord formation as the main reservoirrock, and try to avoid drilling trough the low-pressure BRENT group. Both the Statfjord formation and the BRENT group are deposited during the Jurassic period.

A global transgression was ongoing in the early Jurassic period and the climate was changing from dry to a more humid climate. The northern part of the Vikinggraben was dominated by large river flats, and alluvial sequences such as the Statfjord formation were formed.

Upon the Stafjord formation lays the BRENT group, which is interpreted as a regressiv-transgressiv clastic fan. The rifting in Jurassic led to a relative sea level rise and marine deposits became the dominant in the northern North Sea, with deposition of the organic rich Draupne- and Heater formation (source rocks).

Subsidence combined with a sea level-rise led to a quick burial of the Triassic and Jurassic sediments, and the relief made by the rotated fault blocks in the Vikinggraben was overfilled by sediments by the end of Cretaceous.

1.3 Gullfaks Sør structural geology and petrophysical properties:

Gullfaks Sør is the deepest structure in the Gullfaks area, with top reservoir at 2860 m true vertical depth. Gullfaks Sør is divided into three main structural parts, see figure 1.2. From west to east we find the Domino system, the Accommodation area and the Horst complex. The Domino system is the most dominating part of Gullfaks Sør and occupies the western and central part. It consists of several rotated fault blocks tilted towards east. The Horst Complex is the easternmost part of the field and consists of horst blocks divided by easterly and westerly dipping faults. In between these two main sections we find the Accommodation area. This area has probably acted as a transition zone during the development of the faults between the easterly dipping faults in the Domino system and the westerly dipping faults in the Horst complex. The fact that this area had to adjust to the faulting processes developing on both sides, has probably made it the most complex of the three.

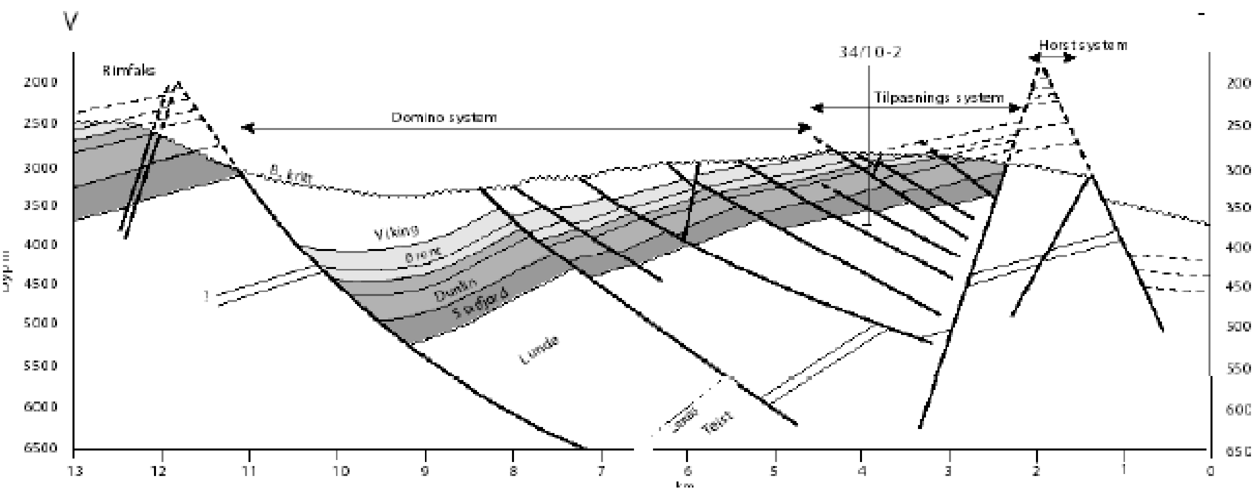


Figure 1.2. The structural geology of Gullfaks Sør.

The Statfjord reservoir lies underneath Brent which can be found at around 2400m depth. Statfjord can be divided into an upper and a lower sequence and these sections can again be divided into different layers. The upper Statfjord consist of the two layers Nansen and Eiriksson-2 and they are together about 70-80 m thick. The lower Statfjord is about 160-175m and consist of the two layers called Eiriksson-1 and Raude.

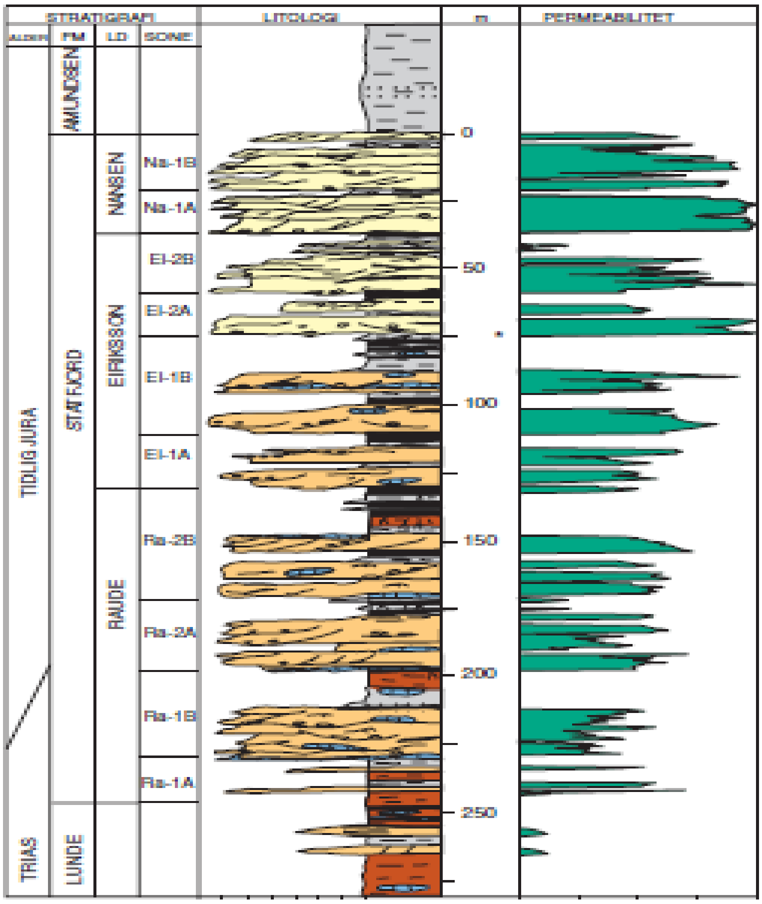


Figure 1.3. The stratigraphic column of the Statfjord formation at Gullfaks Sør.

The reservoir rocks at Statfjord are sandstones from Lower Jurassic and Upper Triassic. The sands in Nansen and the two Eiriksson sections are massive, relatively homogeneous and high permeable (0.5-2D), but with some layers of shale and coal in between. We can see this in figure 1.3. which shows the permeability on the far right and the lithology in the middle. The lateral continuity in the sand in Nansen is especially good. Eiriksson-1 and Raude are characteristic by their alternating shales and sands of different thickness and quality. Raude has a high occurrence of red shales and sections with soil. The lower part of Statfjord has also a higher content of feldspar and kaolinite than the upper part.

As mentioned earlier the field is divided into several blocks separated with faults. Production has showed that the pressure drops relatively fast, which can be an indicator of poor communication between the different blocks. An important reason for this is deformation bands developed in association with the fault growth. These bands were generated by dissolution and recrystallization of quartz which reduces the permeability significantly, and even though they are very thin they affect the flow considerably.

1.3.1 Initial oil saturation:

As we see from figure 2.1. the oil saturation ranges from around 60-95% and it decreases from the gas-oil contact down towards the oil-water contact. In the gas cap and the water zone the saturation of oil is close to zero.

1.3.2 Initial gas saturation:

In figure 2.2 we see how the initial gas saturation is in the reservoir. By comparing this figure with figure 2.1 (all though they are from different angles) we see that at the top of the reservoir where the oil saturation is zero we have a gas cap. Here the gas saturation is around 90-95%; while close to the oil-gas contact the saturation is 70-80% some places.

1.3.3 Porosity:

The initial porosity in Statfjord ranges from around 11-18% as showed in figure 2.2. From Statoil's "Reservoarstyringsplan 2007" in table 3.4.6 it is stated that the porosity in the Statfjord formation is from 24-28% which is much higher than what the model shows. This may be because the table shows the Statfjord field in general and not specifically Gullfaks Sør.

For most of the reservoir the porosity does not change gradually, but has alternating layers of low and higher porosity. This may be layers of sand with shale in between which corresponds to what we see in figure 1.3. The porosity does usually not change much with production unless the compaction is high, due to a large pressure drop. In this model the porosity is assumed to be constant during the production time.

1.3.4 Permeability:

The paper "Reservoar styringsplan 2004" from Statoil states (shortened and translated by Stian S. Haaland).

‘Production experience from wells G-2 HT3 and F-4 AHT3 showed that the pressure fell rapidly, and indicated limited communication. Deformation-bands in connection with faults were interpreted as the main cause of reduced communication. Also dissolution and re crystallization of quartz nearby the deformation-bands has led to highly reduced permeability in the deformation zones.’

From the figures we can see that the permeability in x-direction (Figure 2.3) varies from 0 mD to 200 mD, as suspected from the Statoil-paper. Such a trend can be explained by the geological conditions during deposition and burial (diagenesis). Statfjord formation consists of several different packages of sand and clay / shale, where reservoir-properties will vary accordingly.

High permeable layers are often referred to as "highways", and these highways are in many cases the reason to a large water production, especially if the injector- and producer- wells are not placed correctly.

In the z direction the permeability (Figure 2.4) is very low, ranging from 2-4 mD in large parts of the reservoir. There is a package that has slightly higher permeability (20mD) in the lower part of the reservoir, and if there are to be drilled any horizontal injector-wells this layer should be taken into account and maybe avoided.

‘In well D-4 H (drilled winter 1999/2000) the Statfjord formation was encountered dry approx. 60 m shallower than OWC from the existing fluid model (3362m TVD MHN). This shows that there exists sealing faults on the Statfjord level, and that the reservoir is significantly more complicated than originally assumed.‘

1.4 Gullfaks petrophysics figures

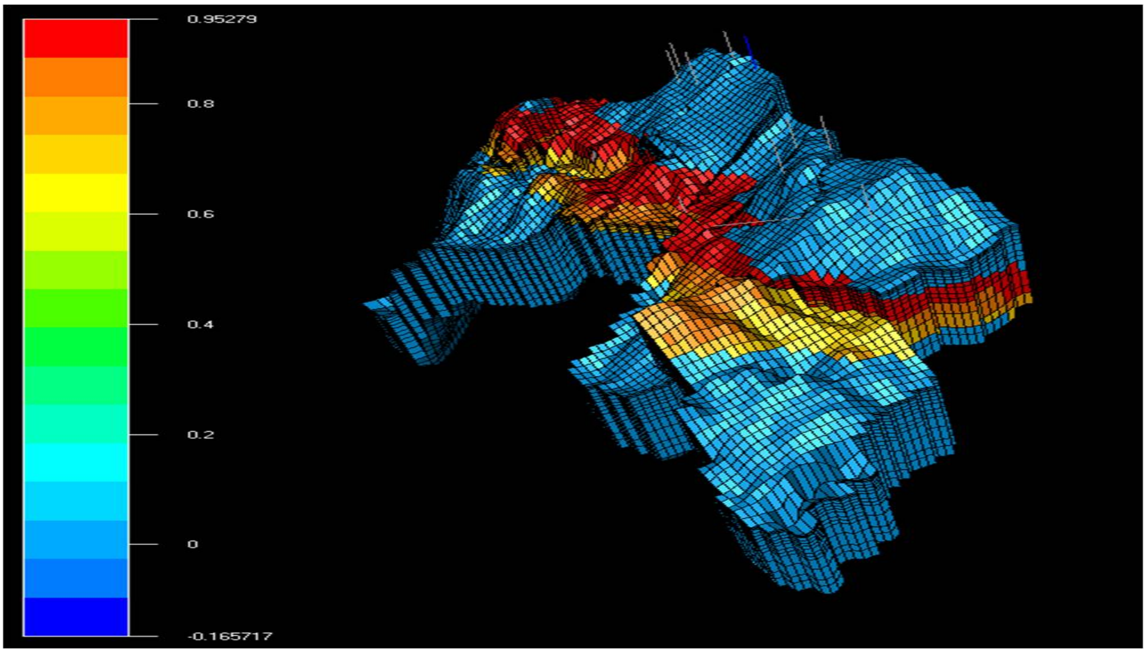


Figure 1.4. Initial oil saturation (fraction) in the reservoir.

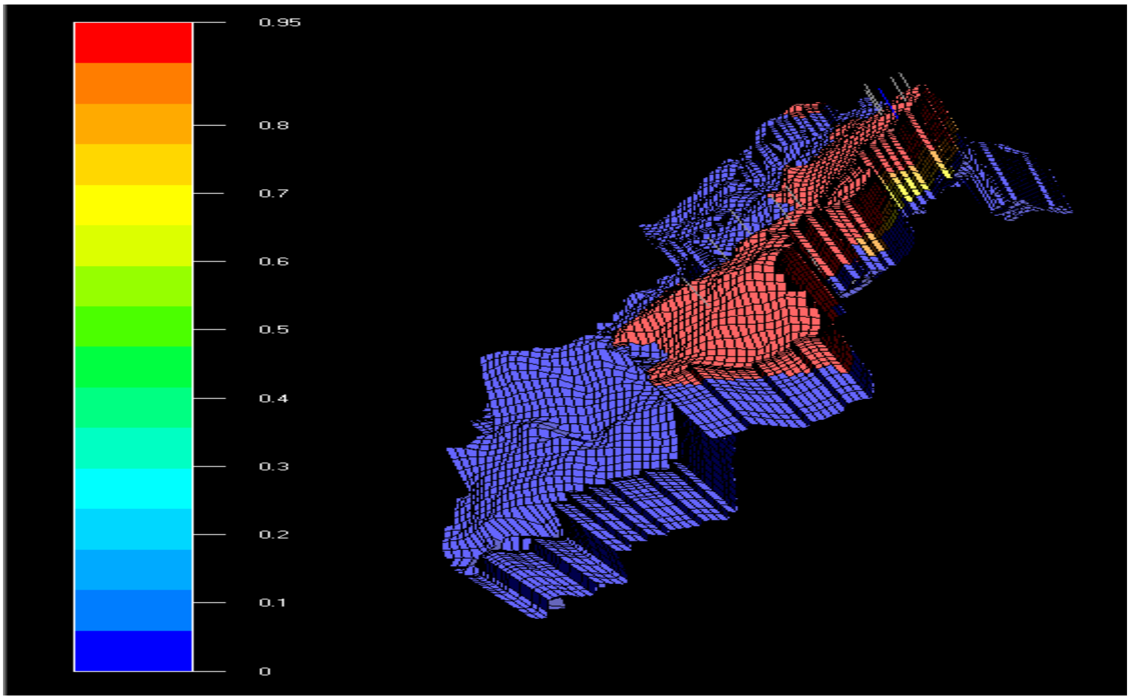


Figure 1.5. Initial Gas saturation (fraction) in the reservoir.

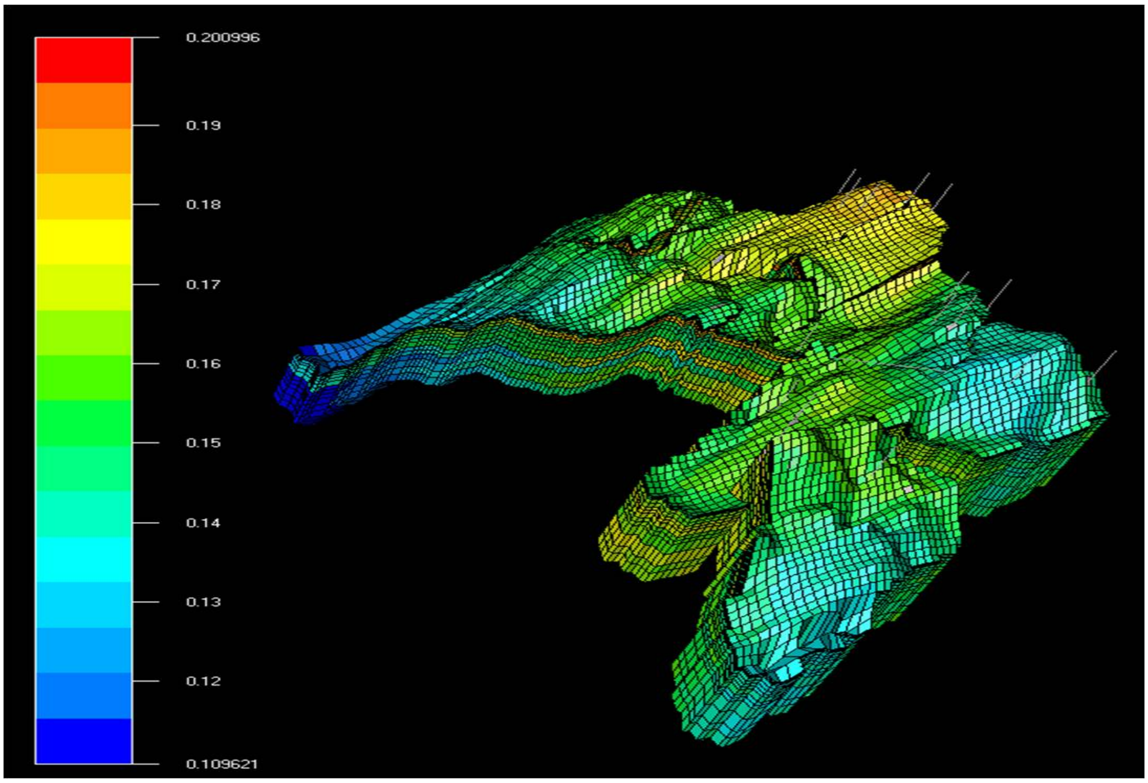


Figure 1.6. Initial porosity(Φ) in the reservoir

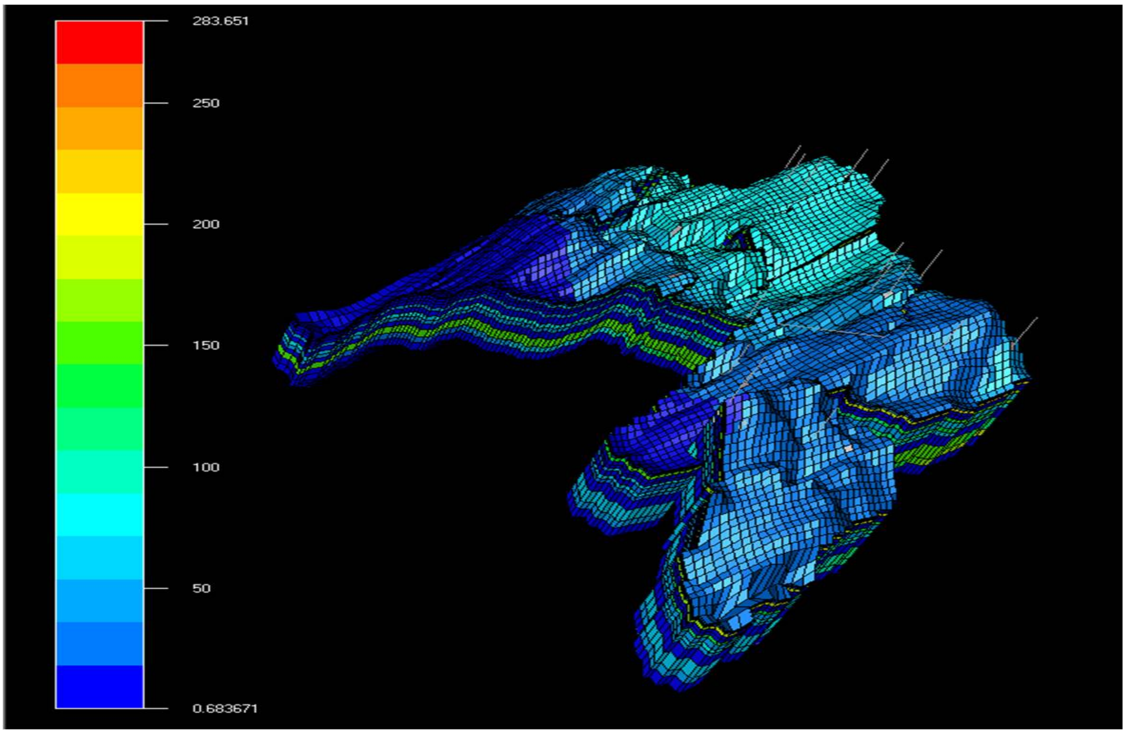


Figure 1.7. Initial permeability(mD) in x-direction in the reservoir.

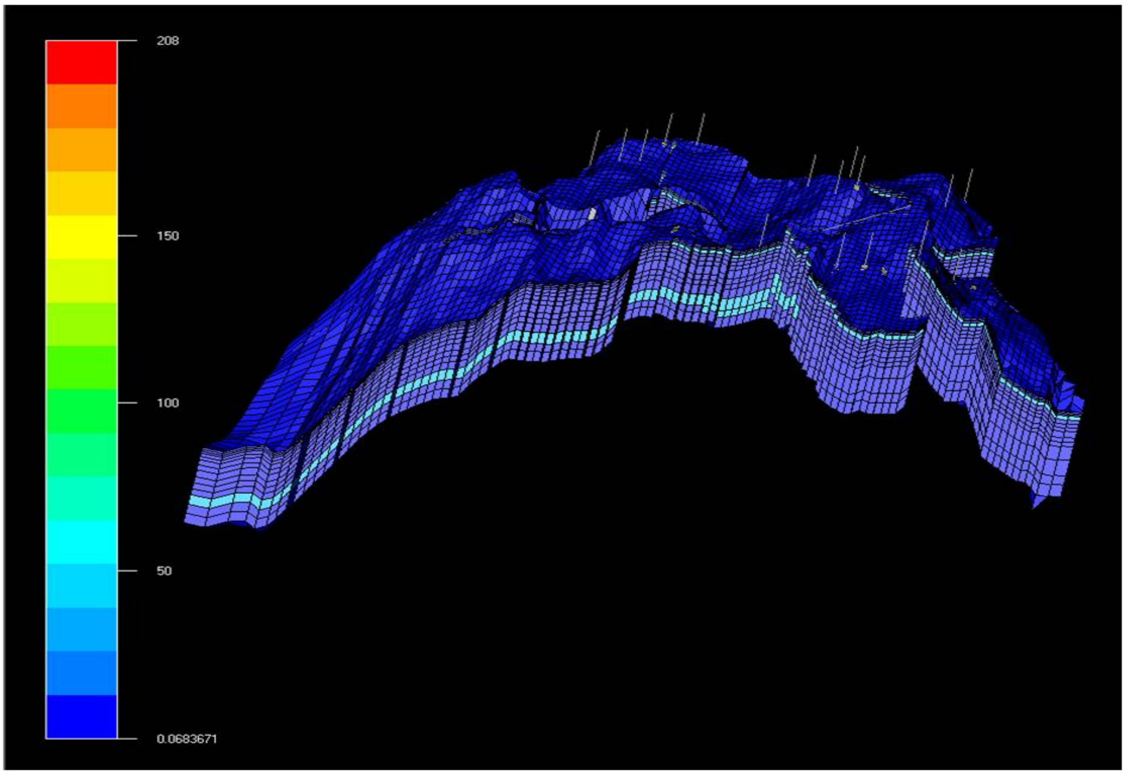


Figure 1.8. Initial permeability(mD) in z-direction in the reservoir.

2 Reservoir Simulation Analysis

2.1 Analysis of history matching.

This chapter of report discusses the analysis of results from history matching and comparsion of reference case of production and new IOR plan. The chapter is supported with the figures and discussions on the results.

The main results of history match between simulation model and data are shown below:

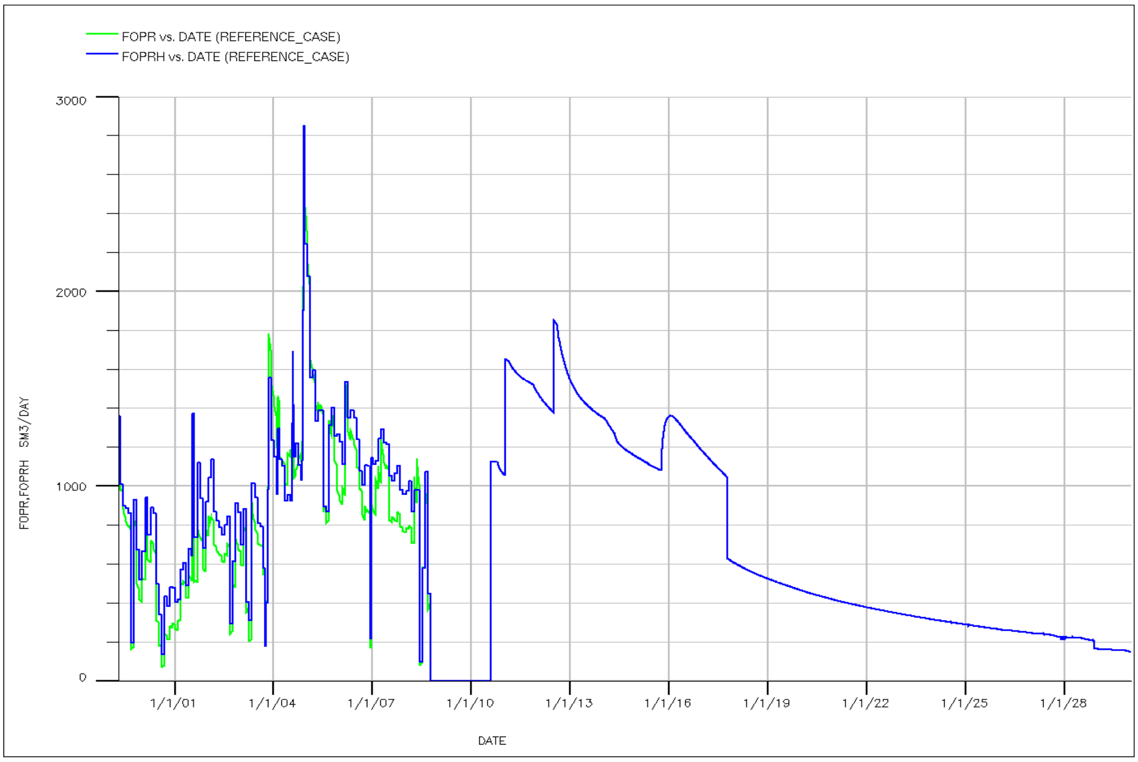


Figure 2.1. Field Oil Production rate history vs. simulation model

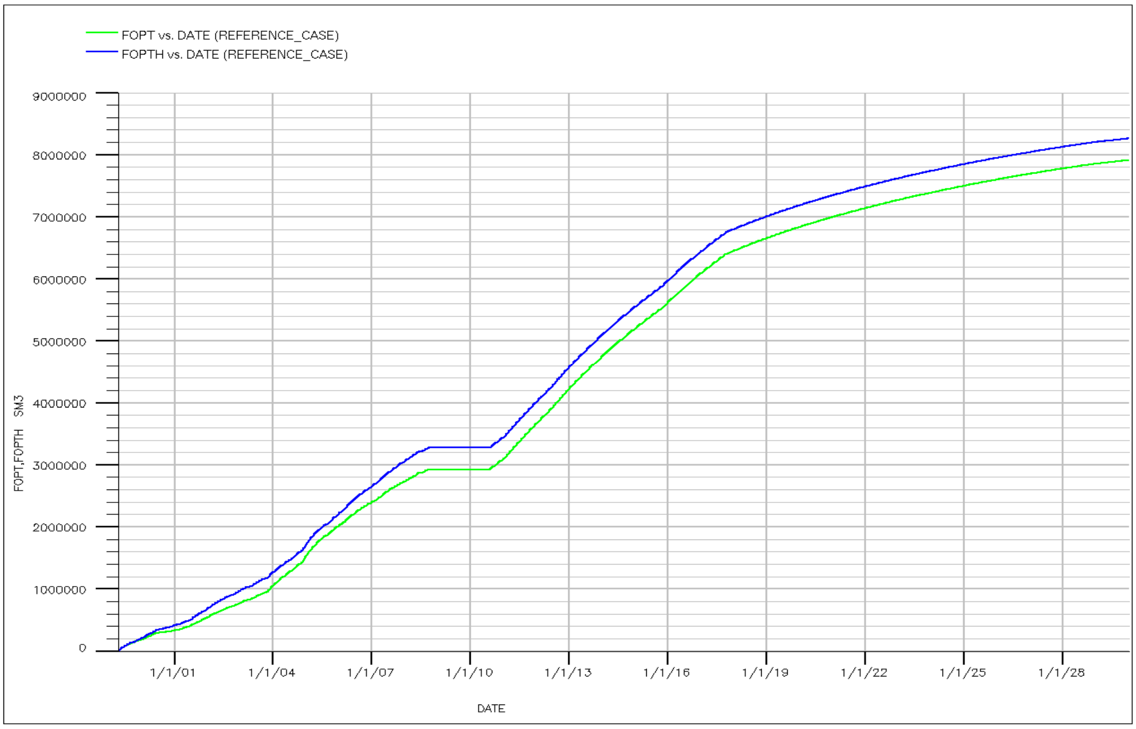


Figure 2.2. Field Cumulative Oil production vs. simulation model

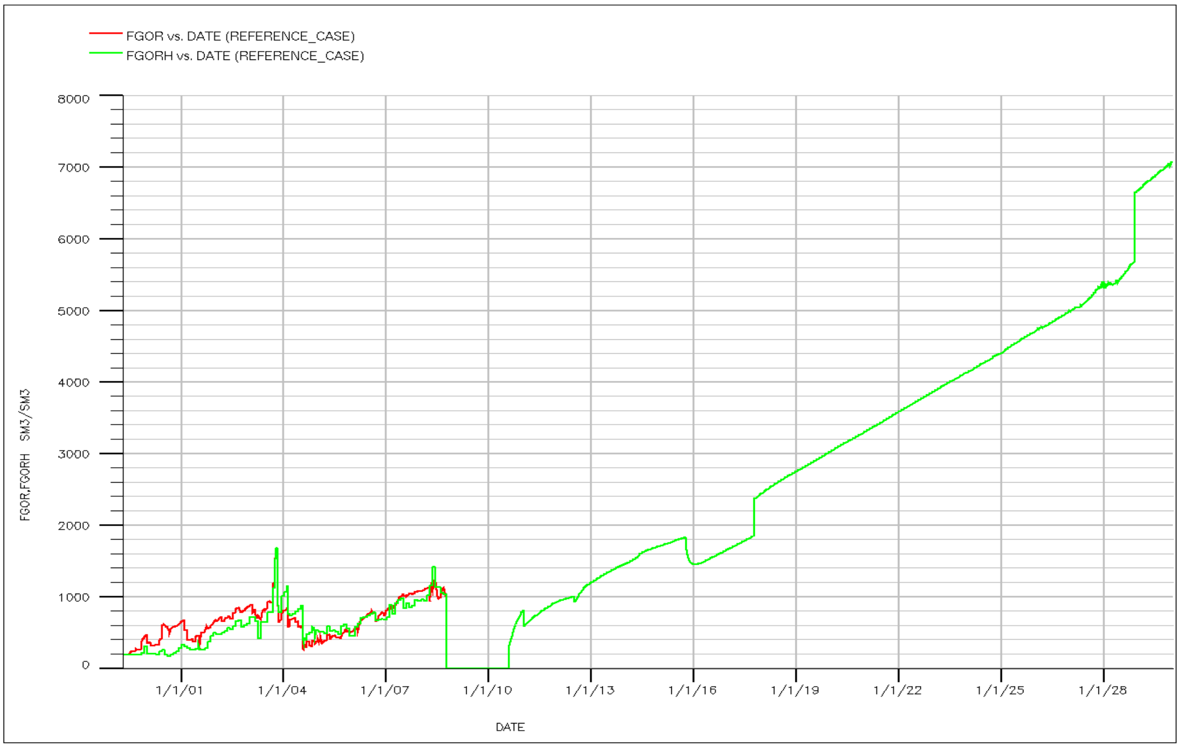


Figure 2.3 . Field Gas Oil Ratio history vs. simulation model

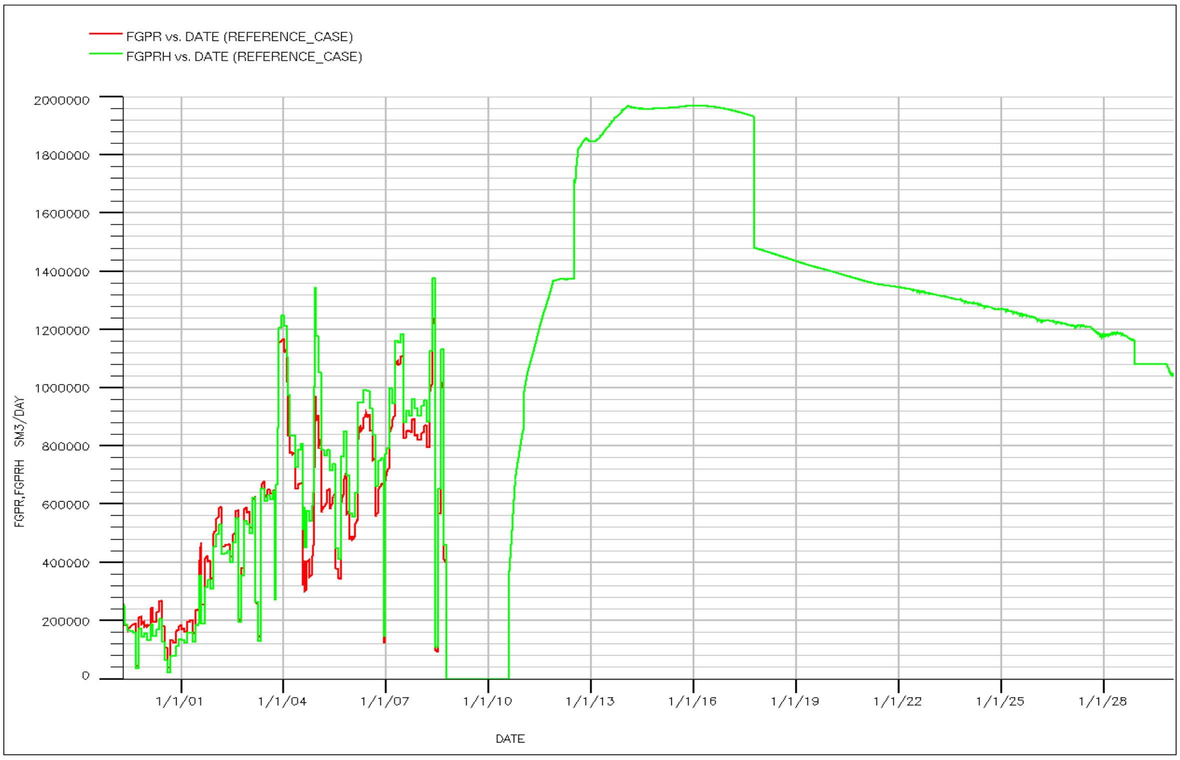


Figure 2.4. Field gas production rate history vs. simulation model

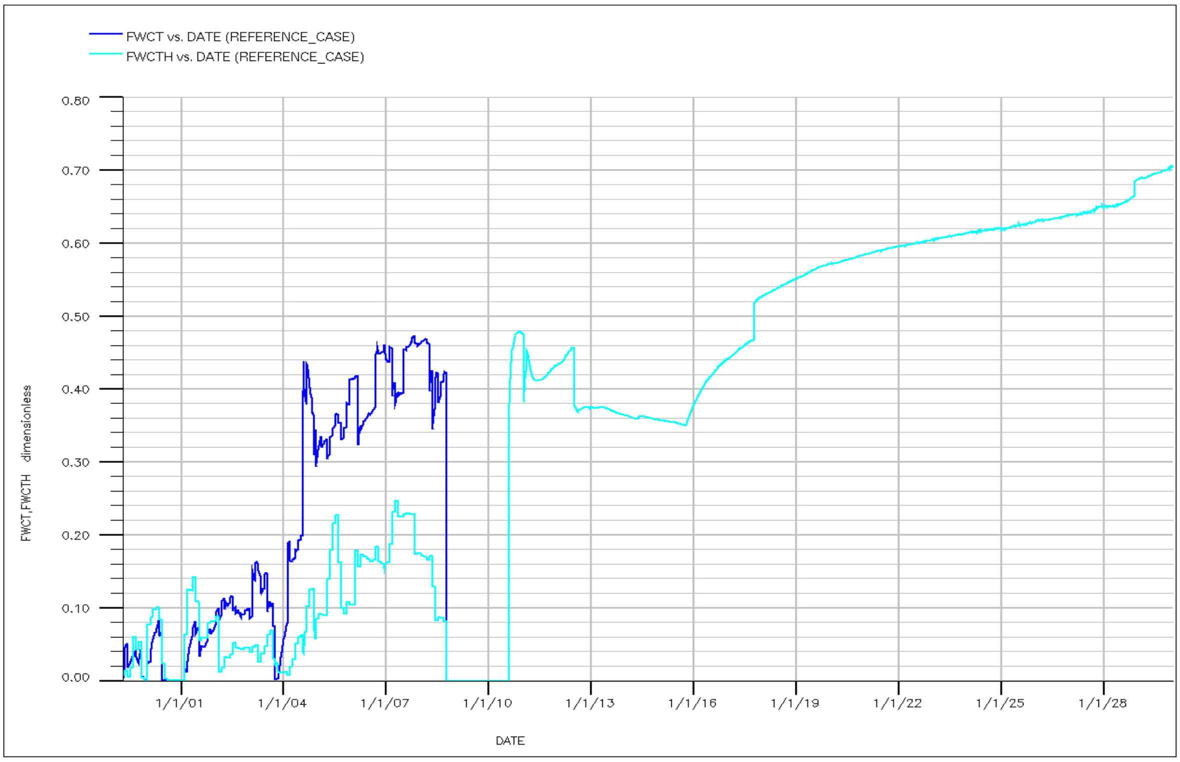


Figure 2.5. Field Water-cut history vs. simulation model

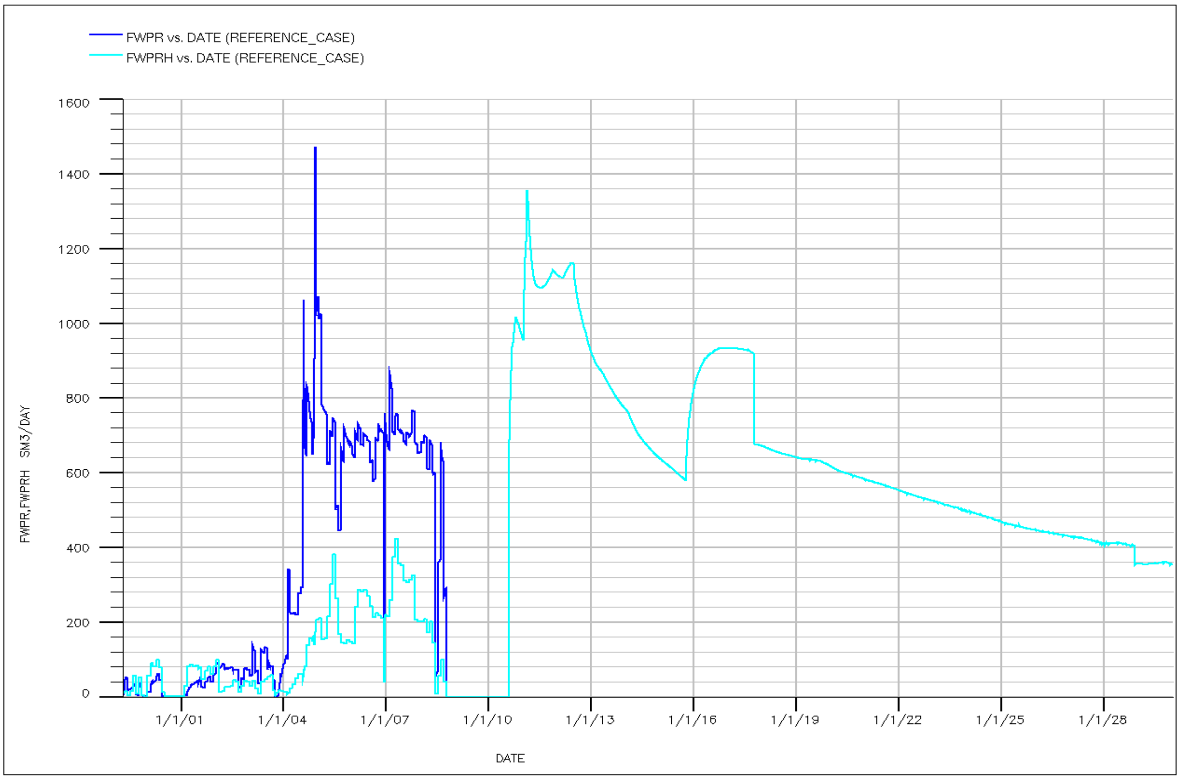


Figure 2.6. Field Water Production rate history vs. simulation model

2.1.1 Discussion the results from History matching.

The main conclusion that we can draw from the simulation match is that in all main operational components of field (FOPR, FGOR, FGPR) we get perfect match except field indications regarding water production. Simulation indicates a lot bigger number than history. The main reason for this could be found if we take a more individual approach to every well existing in the field.

2.2 Analysis new IOR plan with existing reference case of production

Statoil decided to drill 6 new wells: 2 gas injectors (GI-2, GI-4) and 4 producers (W1, W2W3, W4W5, W6W7). The given figures shows the comparison between existing reference case with new IOR plan of Statoil:

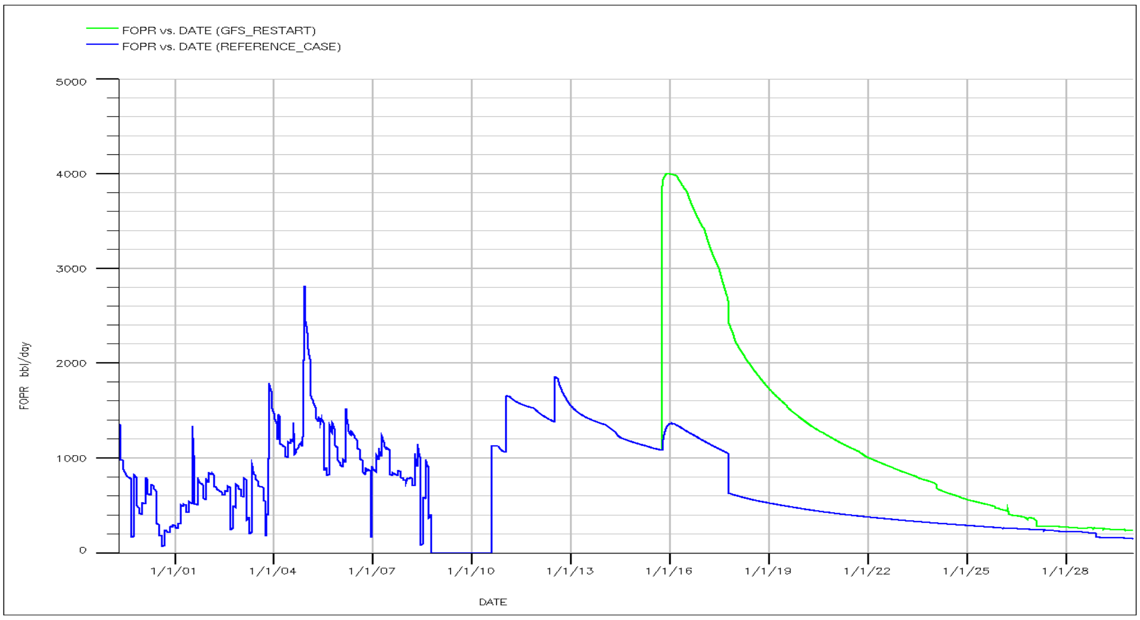


Figure 2.7. Comparison of Reference case and IOR plan of Statoil- Field Oil production rate

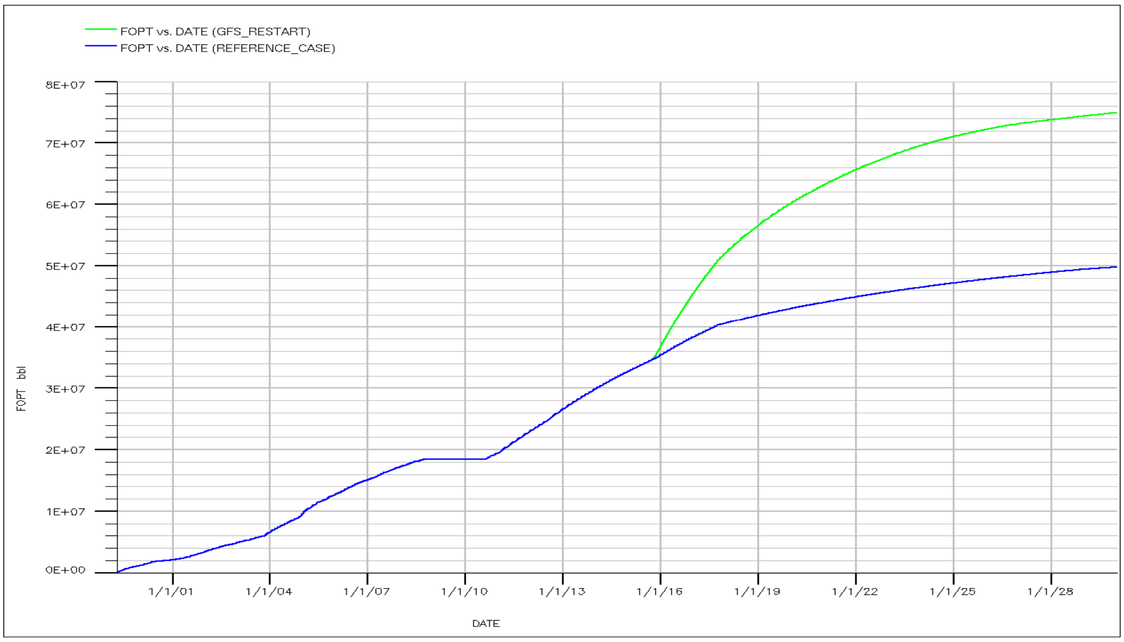


Figure 2.8. Cumulative Oil production comparison

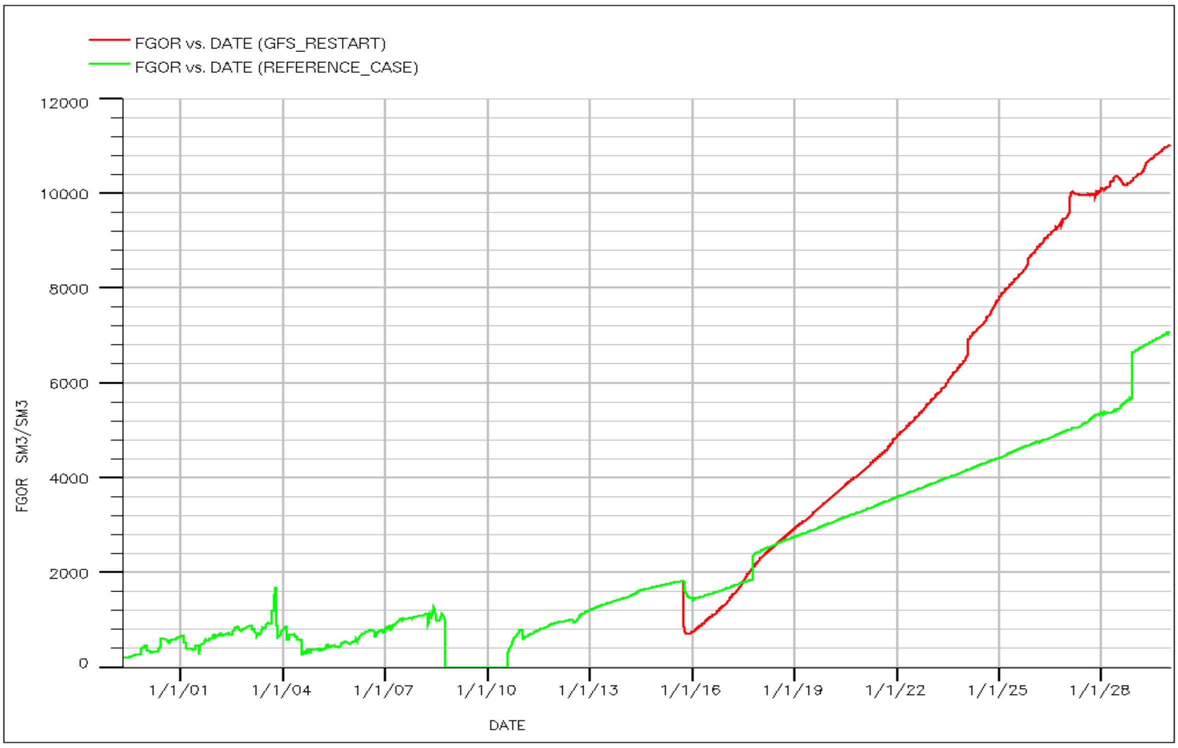


Figure 2.9. Field GOR comparison

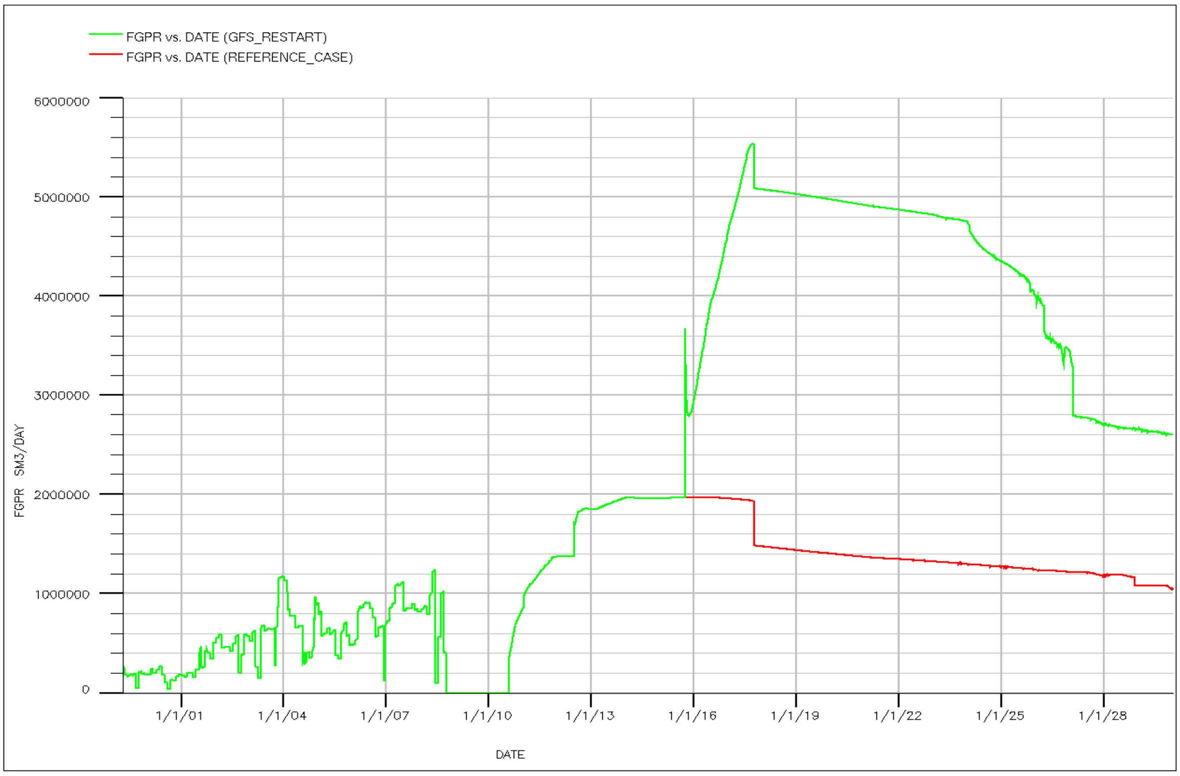


Figure 2.10. Field Gas production rate

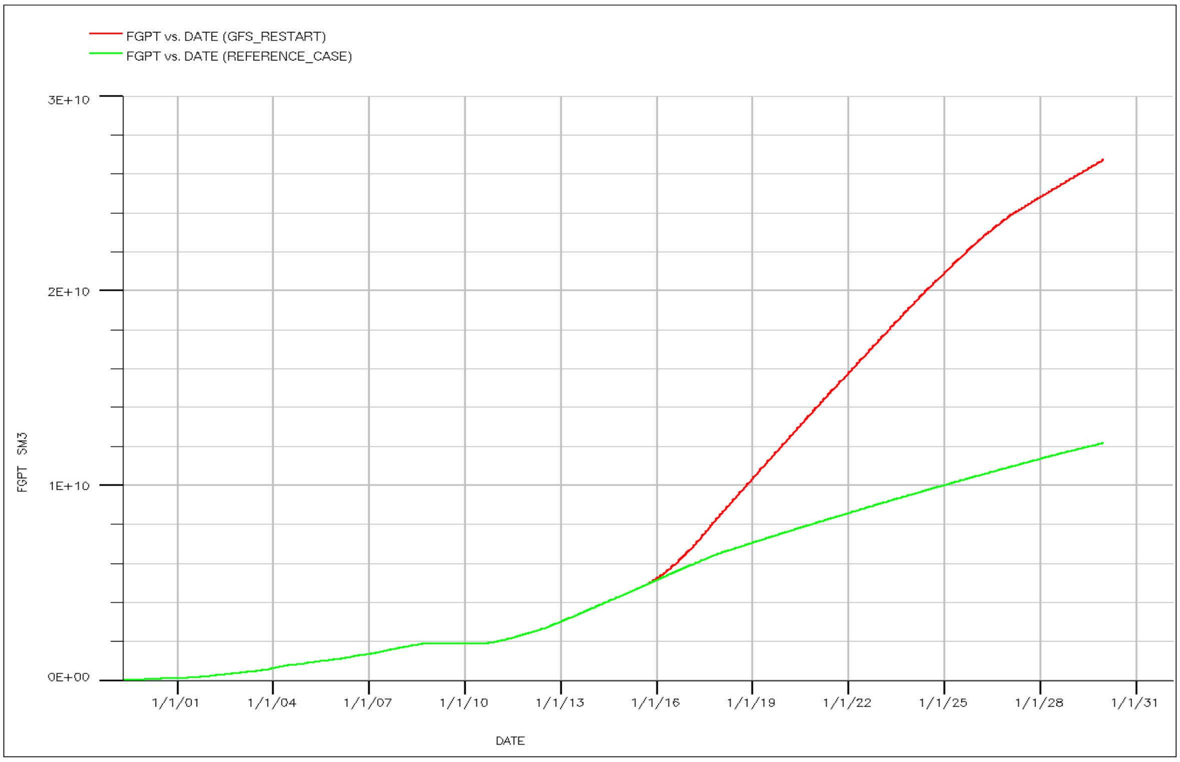


Figure 2.11. Field gas production total

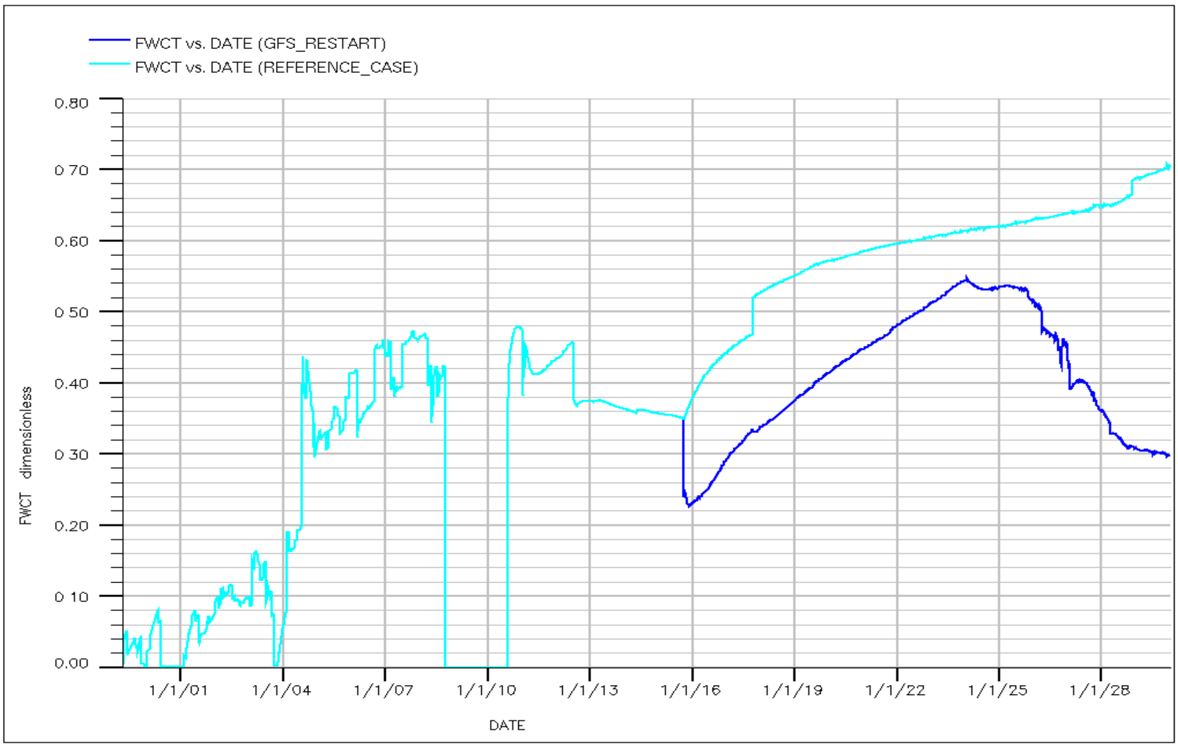


Figure 2.12. Field water cut

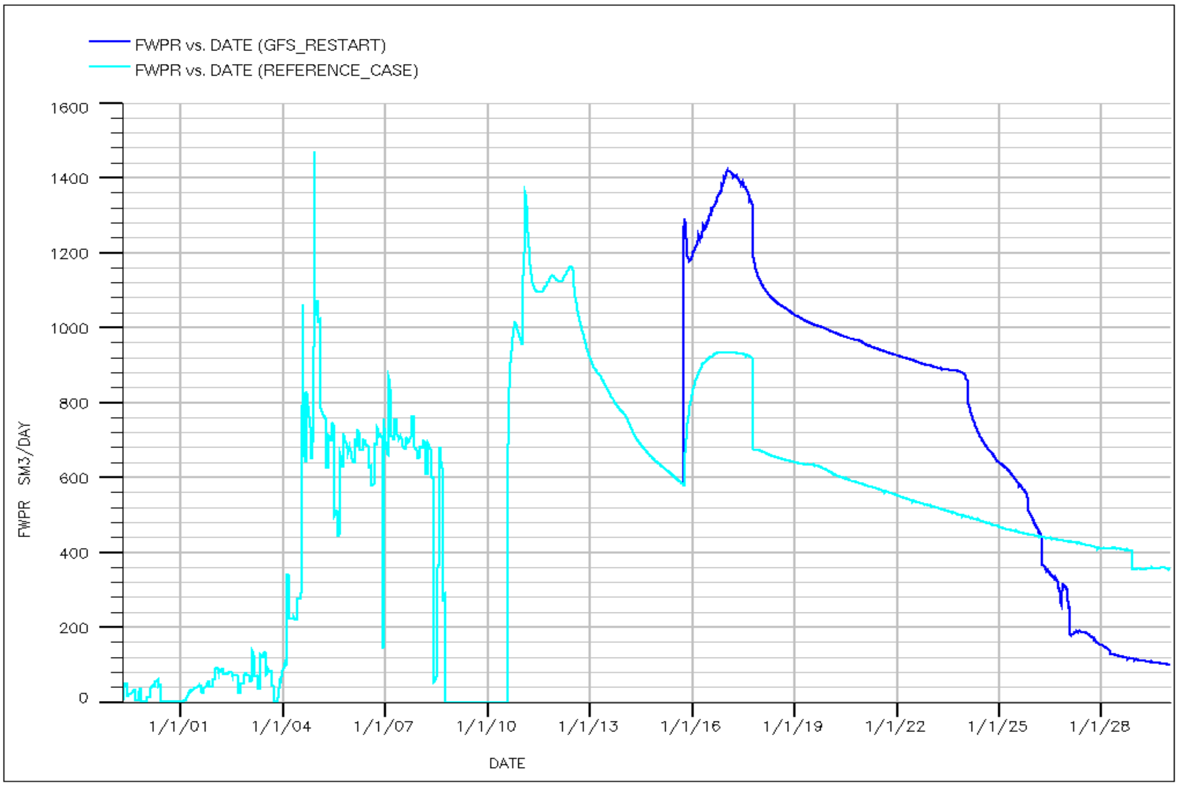


Figure 2.13. Field water production rate

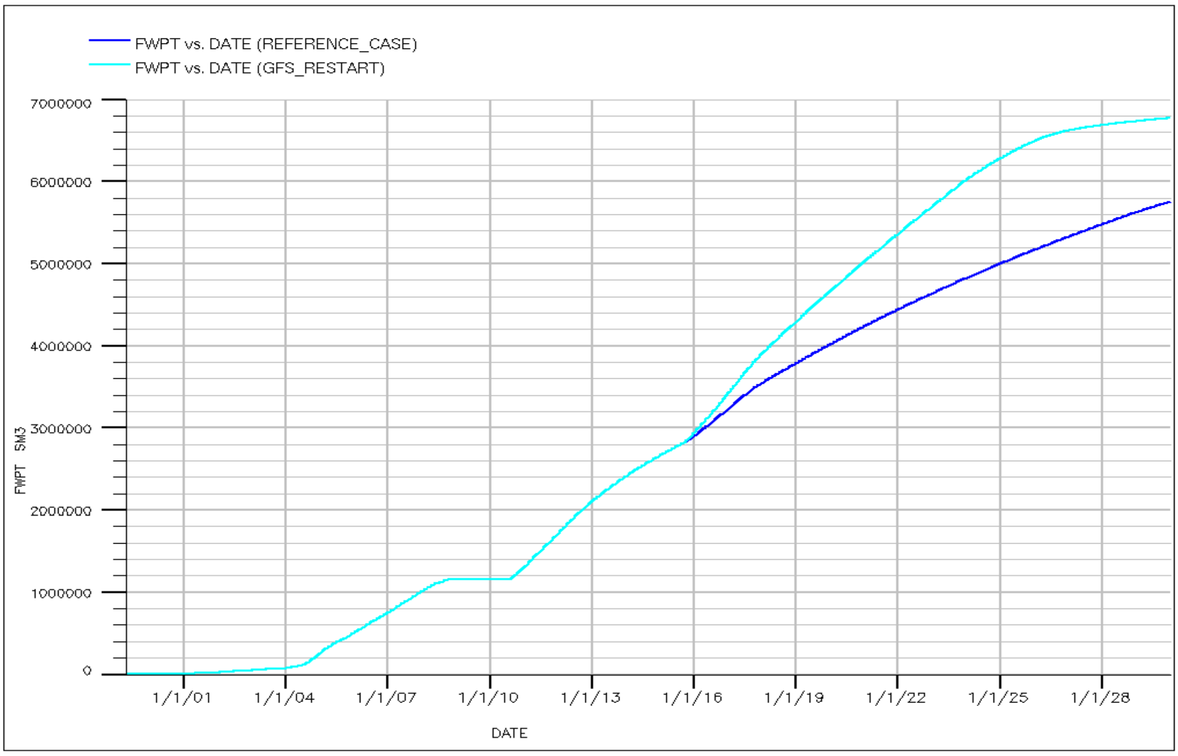


Figure 2.14. Field cumulative production volume

2.2.1 Discussion of comparison between reference case and new IOR plan.

As it can be seen from figure 2.1 new wells are giving increase in Field Oil production rate. But this increase does not last for very long time. GOR analysis of the field (figure 2.3) shows in first 2 years of injection it GOR decreases then it suddenly surpasses the GOR profile of field with reference case without new wells. It can be seen from figures 2.4 and 2.5 that Gas production of new IOR plan is much higher than that of reference case. Looking at figures of Water cut, water production rate and cumulative water production, we can conclude that new plan gives higher production of water than reference case plan. The higher production water and sudden increase of gas production could be one of the reasons for not consistent field oil production rate. Since reservoir management plan of Gullfaks Sør does not give enough information about pressure communication between the segments, it is becoming hard to say which wells are contributing to this production profile of the field. Therefore individual well performance analysis should be made before any conclusion is drawn.

2.3 Comparison of individual new production wells

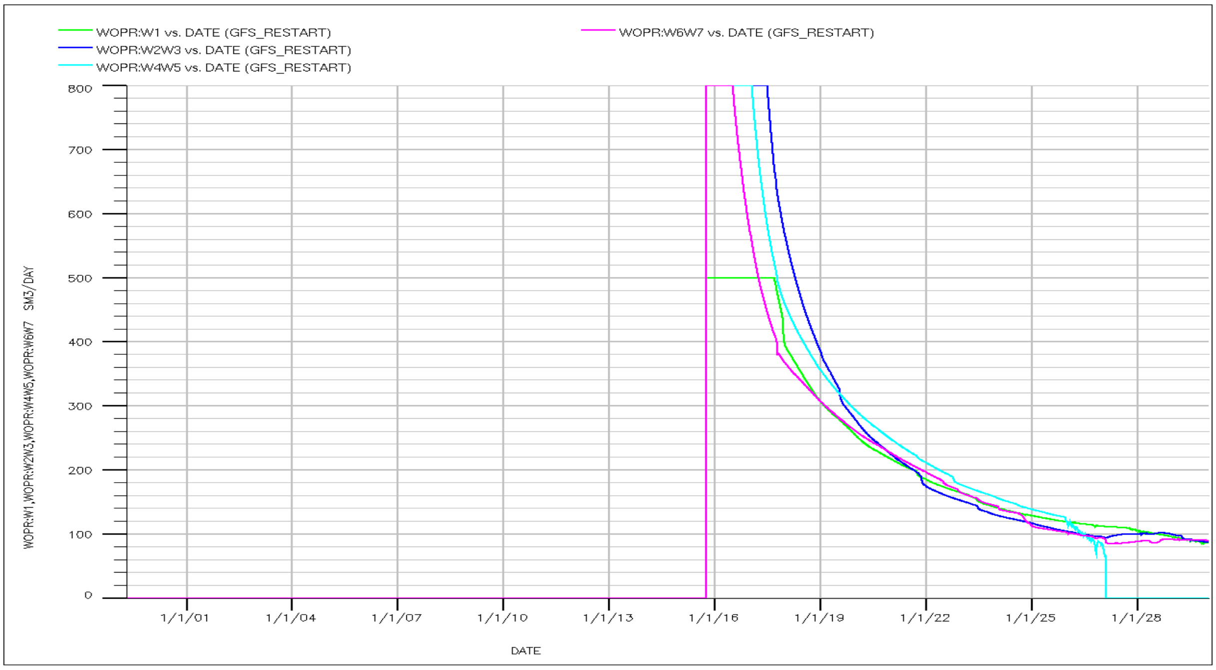


Figure 2.15 Field Oil production rate comparisons of new wells

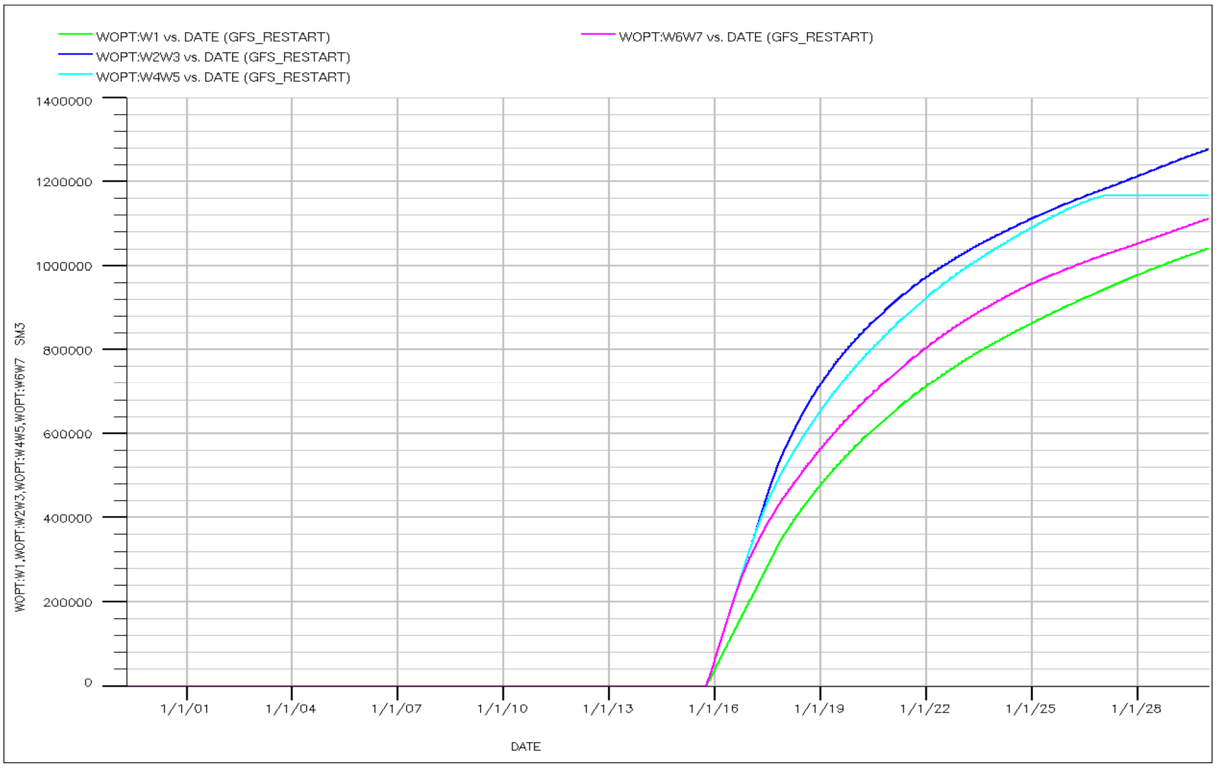


Figure 2.16. Field Cumulative oil production of new wells

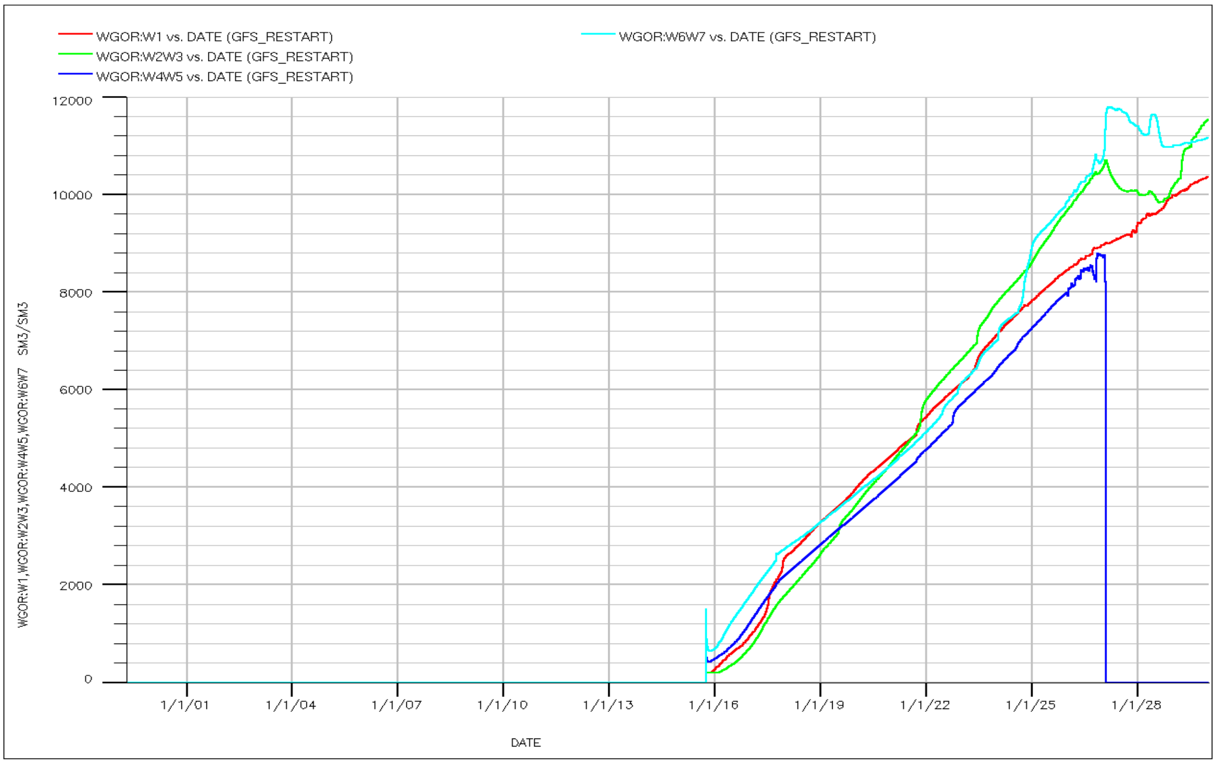


Figure 2.17 Field GOR comparisons of new wells

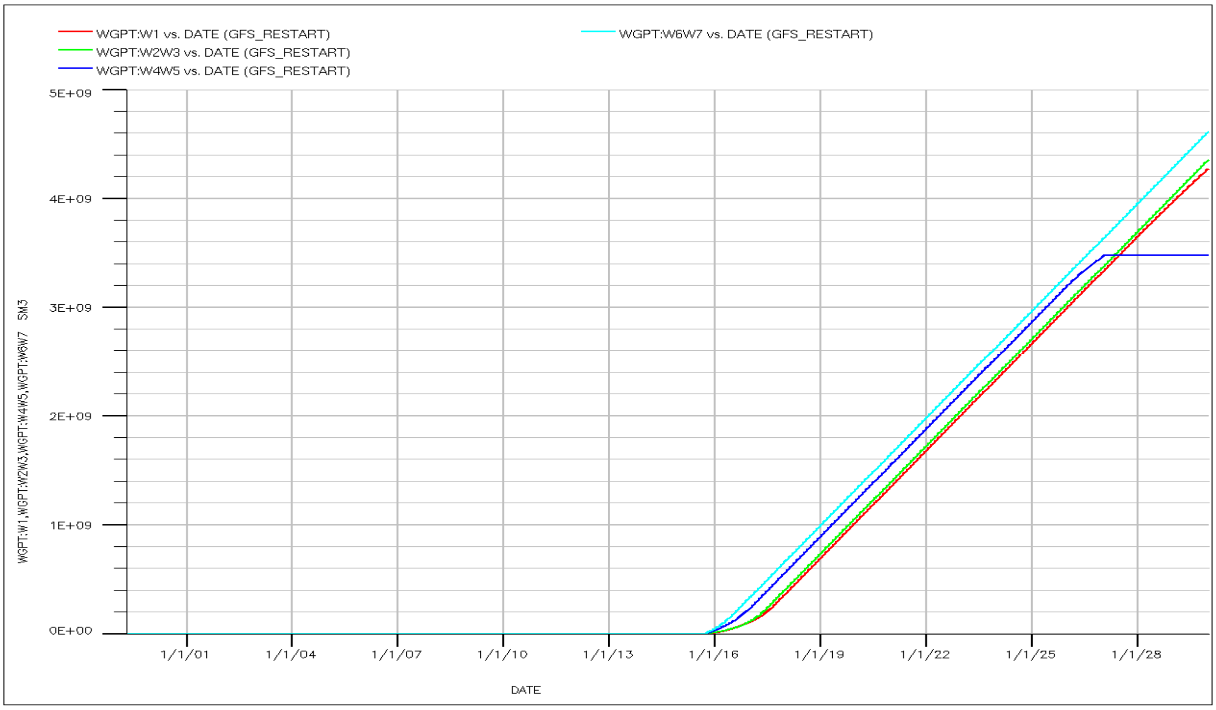


Figure 2.18.Field cumulative gas production comparisons of wells

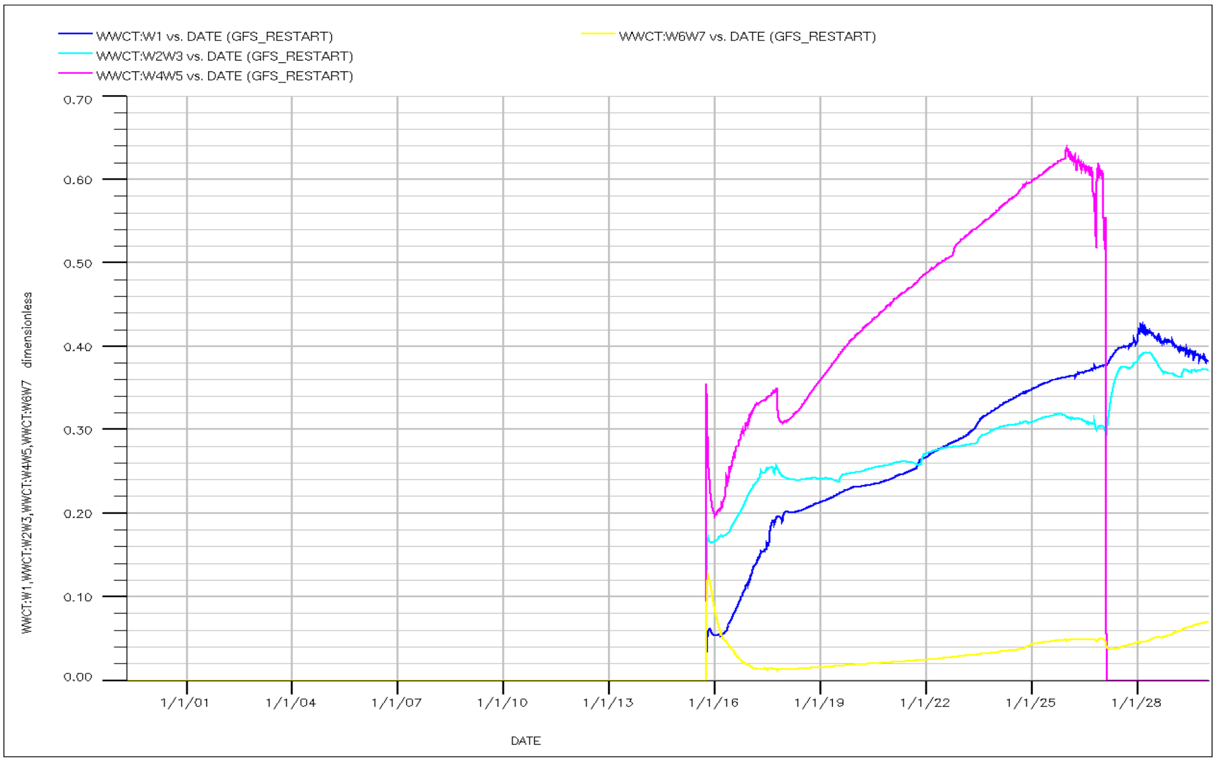


Figure 2.19. Field water cut comparison of new wells

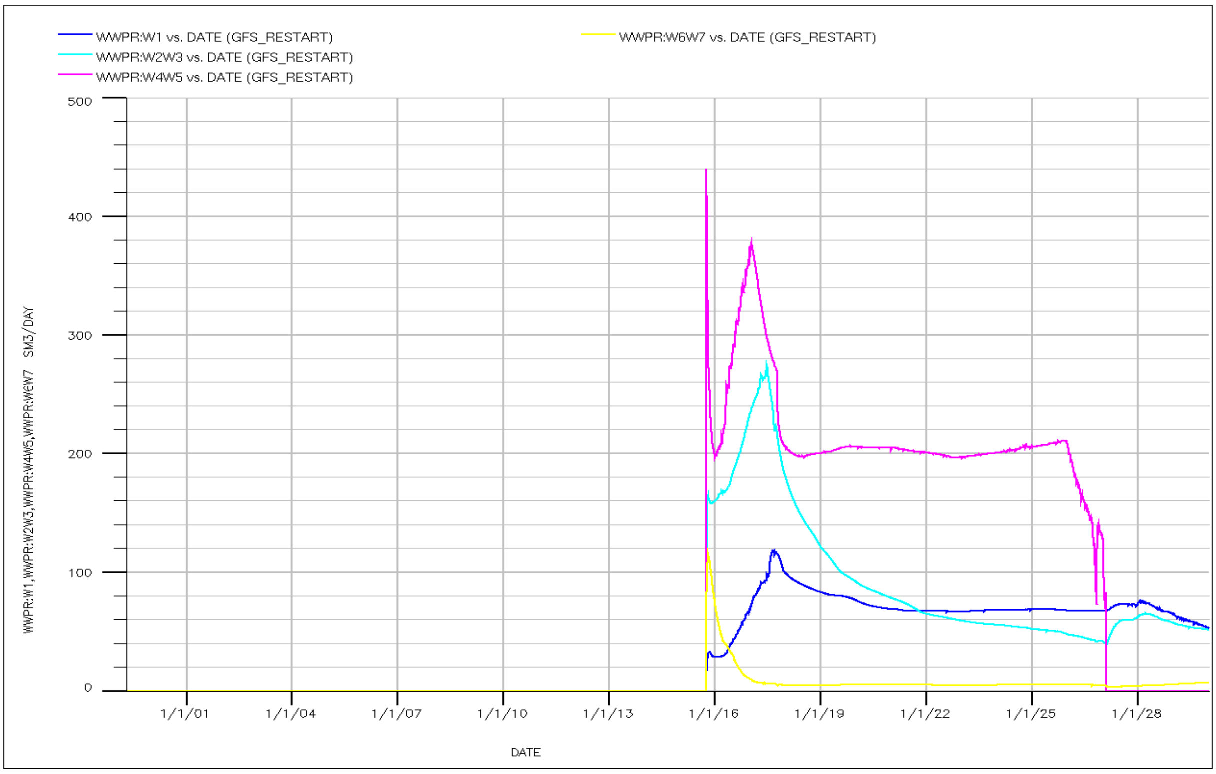


Figure 2.20 Field water production comparisons from new wells

2.3.1 Discussion of results:

The information shows that well W1 gives less production than other wells. And also results reveal that well W4W5 stops production before the other well. And this well gives the most water production, but it gives the lowest GOR. The GOR gaps among individual wells are very low, therefore it is hard to say which well can contribute the most to the sudden increase in gas production. Concluding from the figures given, for more detailed analysis we need more information about the level of communication between segments, pressure connectivity between segments. After enough information we can say if there is a case of unstable displacement or possible coning effects.

3 Economic Evaluation

3.1 Objectives:

Using Net Present Value (NPV) technique in order to:

- Economical analyzing between two given alternatives for extended case; establishing a new drilling platform alternative and subsea alternative.
- Economical analyzing between extended case and reference case.

3.2 Assumptions:

Cost and other needed data for economic evaluation are not available. Therefore, some assumptions have been assumed that are listed in following:

- Interest rate = 5%
- exchange rate NOK/USD = 6
- Oil Price will start by 75 ($/bbl) in 2015 then will increase by 4% every year. It could vary between +/- 40%

- Gas Price will start by 2 (NOK/Sm^3) in 2015 then will increase by 2% every year. It could vary between +/- 40%
- CAPEX cost for drilling platform (Alternative 1) consist of: (It could vary between +/- 40%)
  - Establishing a new platform cost = 1.00E+10 NOK
  - Drilling cost = 1.00E+08 NOK per well
- CAPEX cost for subsea (Alternative 2) consist of: (It could vary between +/- 40%)
  - Renting drill ship cost for 6 months = 3.24E+08 NOK
  - Drilling and subsea platform cost = 1.75E+09 NOK
- OPEX cost for each year = 2.5 % of summarize the total CAPEX cost and yearly oil incomes.
- Because of uncertainty, three possible cases are determined for each alternative :
  - Base case by 60% probability which is most likely case. For this case normal cost data have been used.
  - Worse case by 20% probability which is worse possible case that might be happened. For this case lowest data in oil and gas price (-40%) and highest data in CAPEX and OPEX cost (+40%) have been used.
  - Best case by 20% probability which is best possible case that might be happened. For this case highest data in oil and gas price (+40%) and lowest data in CAPEX and OPEX cost (-40%) have been used.
- Amount of gas which will be reused for injection, has been subtracted from gas production.

3.3 Economical Analysis between two given alternatives for extended case:

As the details are shown and tabulated in attachment1, the following final results have been obtained:

Alternative1 – Establishing a drilling platform		Alternative2 – subsea platform	
Total NPV for Base Case	18,381 Million NOK	Total NPV for Base Case	29,119 Million NOK
Total NPV for Worse Case	138 Million NOK	Total NPV for Worse Case	15,172 Million NOK
Total NPV for Best Case	36,623 Million NOK	Total NPV for Best Case	43,066 Million NOK

Table 3.1

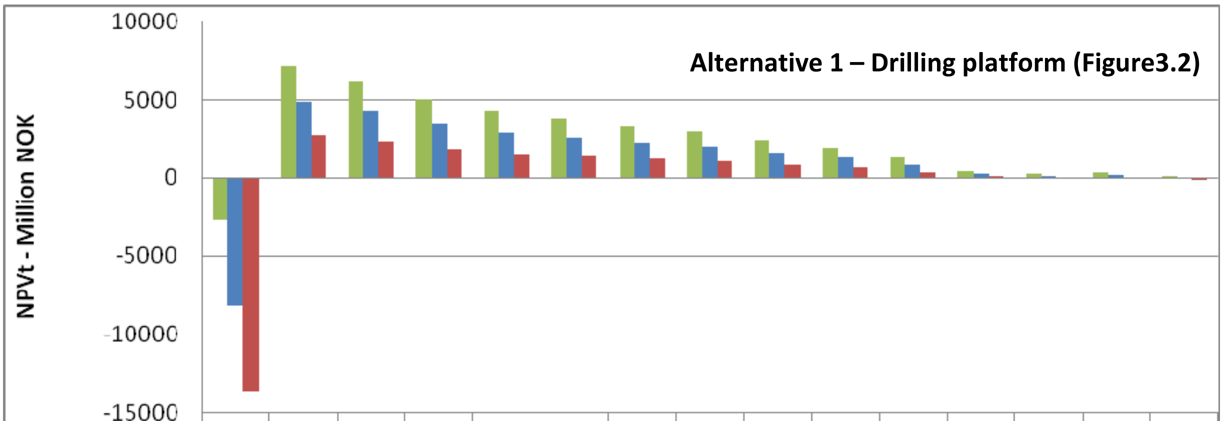
These results show that in all three possible cases, alternative 2 will be more beneficial rather than alternative 1 for investment. Though, reaching to these results was not unexpected because revenues of oil and gas for both alternatives are the same and the CAPEX cost for alternative 1 is considerably more than alternative 2.

The most CAPEX expense for alternative 1 related to platform construction cost. So, if it will be a floating platform and it will be possible to reuse this platform for further projects and drilling other wells with, then alternative 1 could be more beneficial in long term rather than alternative2. But just talking about this project, obviously alternative 2 will be more beneficial.

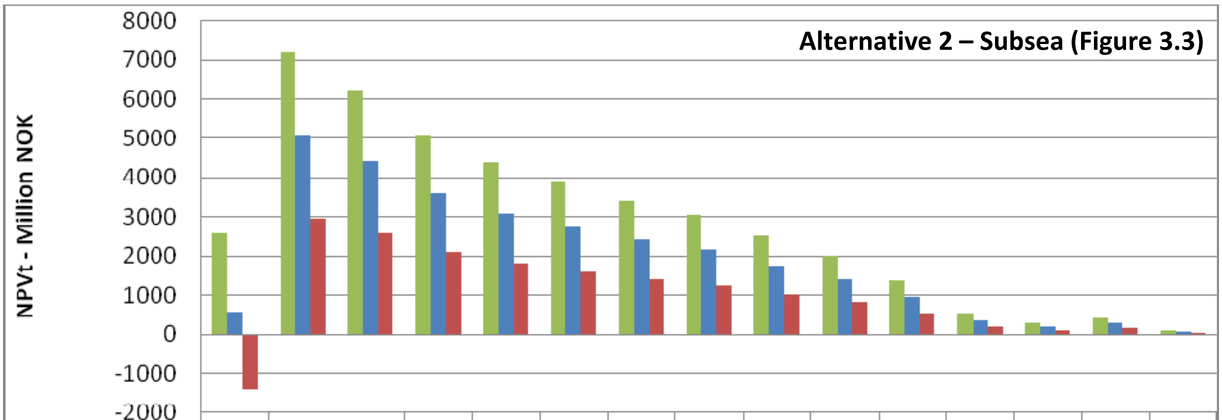
3.4 Economical analyzing between extended case and reference case:

As it is shown in table 1, all six possible cases in both alternatives imply that extended case in compare by reference case would be more beneficial.

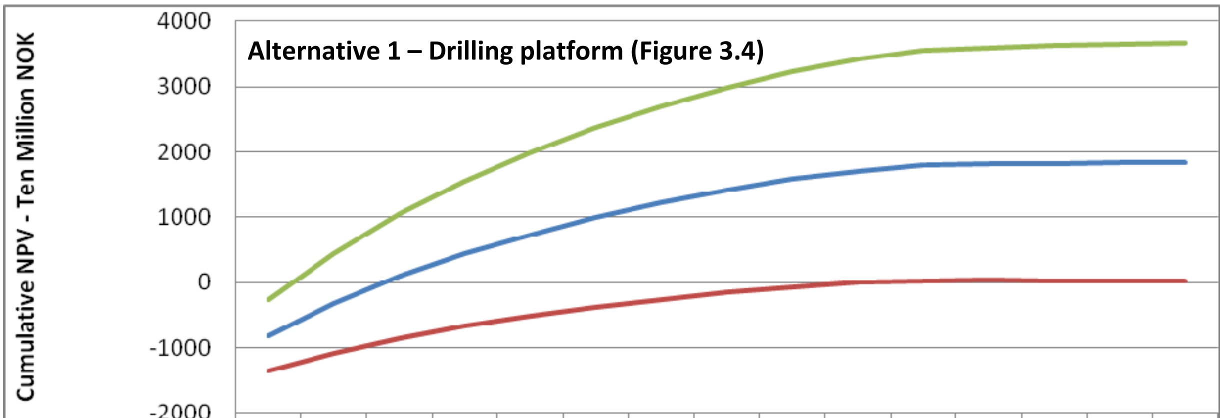
By considering following figures, the possibility for more detailed analysis will be provided. The earned NPV for each year between 15 Oct 2015 to 1 Jan 2030, are depicted as following figures;



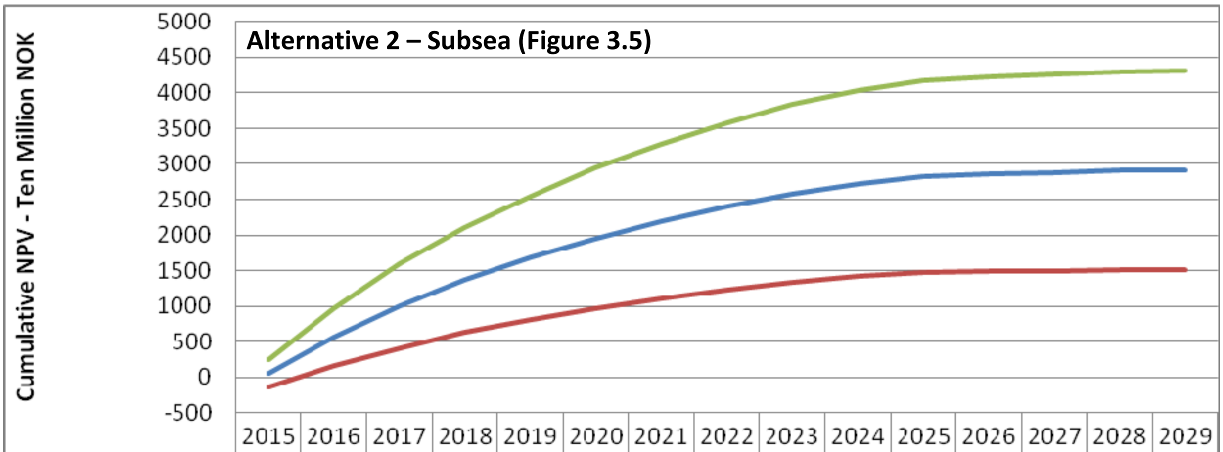
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-2673	7079	6136	5004	4280	3790	3325	2960	2417	1924	1293	466	235	359	28
BASE NPV	-8147	4891	4232	3434	2926	2585	2260	2005	1624	1278	833	247	87	179	-53
WORSE NPV	-1362	2703	2327	1864	1573	1379	1194	1051	831	632	373	29	-61	-1	-134



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	2564	7195	6247	5109	4380	3886	3416	3046	2499	2003	1368	537	303	423	90
BASE NPV	582	5084	4416	3609	3093	2744	2411	2149	1761	1409	958	366	200	286	50
WORSE NPV	-1400	2973	2584	2110	1807	1601	1406	1253	1024	815	547	195	97	149	10



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	-267	441	1054	1555	1983	2362	2694	2990	3232	3424	3554	3600	3624	3659	3662
BASE NPV	-815	-326	98	441	734	992	1218	1419	1581	1709	1792	1817	1825	1843	1838
WORSE NPV	-1362	-1092	-859	-673	-515	-378	-258	-153	-70	-7	31	33	27	27	14



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
BEST NPV	256	976	1601	2112	2550	2938	3280	3584	3834	4035	4171	4225	4255	4298	4307
BASE NPV	58	567	1008	1369	1678	1953	2194	2409	2585	2726	2822	2858	2878	2907	2912
WORSE NPV	-140	157	416	627	807	968	1108	1233	1336	1417	1472	1492	1501	1516	1517

As it is shown in figures 3.2 and 3.3; Although the total NPV for all six case (for both alternatives) becomes positive that it implies going through extended case will be economical, but there are some negative numbers for some years, negative numbers in first year obviously are because of investment cost (CAPEX) and are expected. But the negative numbers in 2029 and 2027 for base and worse cases of alternative1 respectively, mean that if alternative1 will be chosen, for base case until 2029 and for worse case until 2027 would be economical to produce oil and gas from wells in extended case.

Moreover, as it is shown in figure 3.3 and 3.4; The "***Break-even-points***" for all cases could be resulted:

Alternative1 – Drilling Platform		
Best case: End of 2015	Base case: End of 2016	Worse case: End of 2024
Alternative2 - Subsea		
Best case: -	Base case: -	Worse case: End of 2015

3.5 Sensitive Analysis:

Due to uncertainty, there are four variables here that might be varied between +/- 40% by assumed probability.

- Oil price
- Gas price
- CAPEX cost
- OPEX cost

These variables could effect on NPV, Sensitive analysis shows that how much the total NPV is sensitive by changing each these four variables.

Alternatine 1 (Platform Analysis)				Alternatine 2 (Subsea)			
Oil Price (NOK/BBL)	**Low**	**Base**	**High**	**Oil Price** (NOK/BBL)	**Low**	**Base**	**High**
% Change	-40.00%	0%	40.00%	% Change	-40.00%	0%	40.00%
NPV (MNOK)	14185	18381	22576	NPV (MNOK)	24924	29119	33314
% Change	-22.83%	0%	22.83%	% Change	-14.41%	0%	14.41%
Gas Price (NOK/Sm^3)	**Low**	**Base**	**High**	**Gas Price** (NOK/Sm^3)	**Low**	**Base**	**High**
% Change	-40.00%	0%	40.00%	% Change	-40.00%	0%	40.00%
NPV (MNOK)	9779	18381	26983	NPV (MNOK)	20517	29119	37721
% Change	-46.80%	0%	46.80%	% Change	-29.54%	0%	29.54%
OPEX	**Low**	**Base**	**High**	**OPEX**	**Low**	**Base**	**High**
% Change	-40.00%	0%	40.00%	% Change	-40.00%	0%	40.00%
NPV (MNOK)	19586	18381	17175	NPV (MNOK)	29439	29119	28799
% Change	6.56%	0%	-6.56%	% Change	1.10%	0%	-1.10%
CAPEX	**Low**	**Base**	**High**	**CAPEX**	**Low**	**Base**	**High**
% Change	-40.00%	0%	40.00%	% Change	-40.00%	0%	40.00%
NPV (MNOK)	22621	18381	14141	NPV (MNOK)	29949	29119	28289
% Change	23.07%	0%	-23.07%	% Change	2.85%	0%	-2.85%

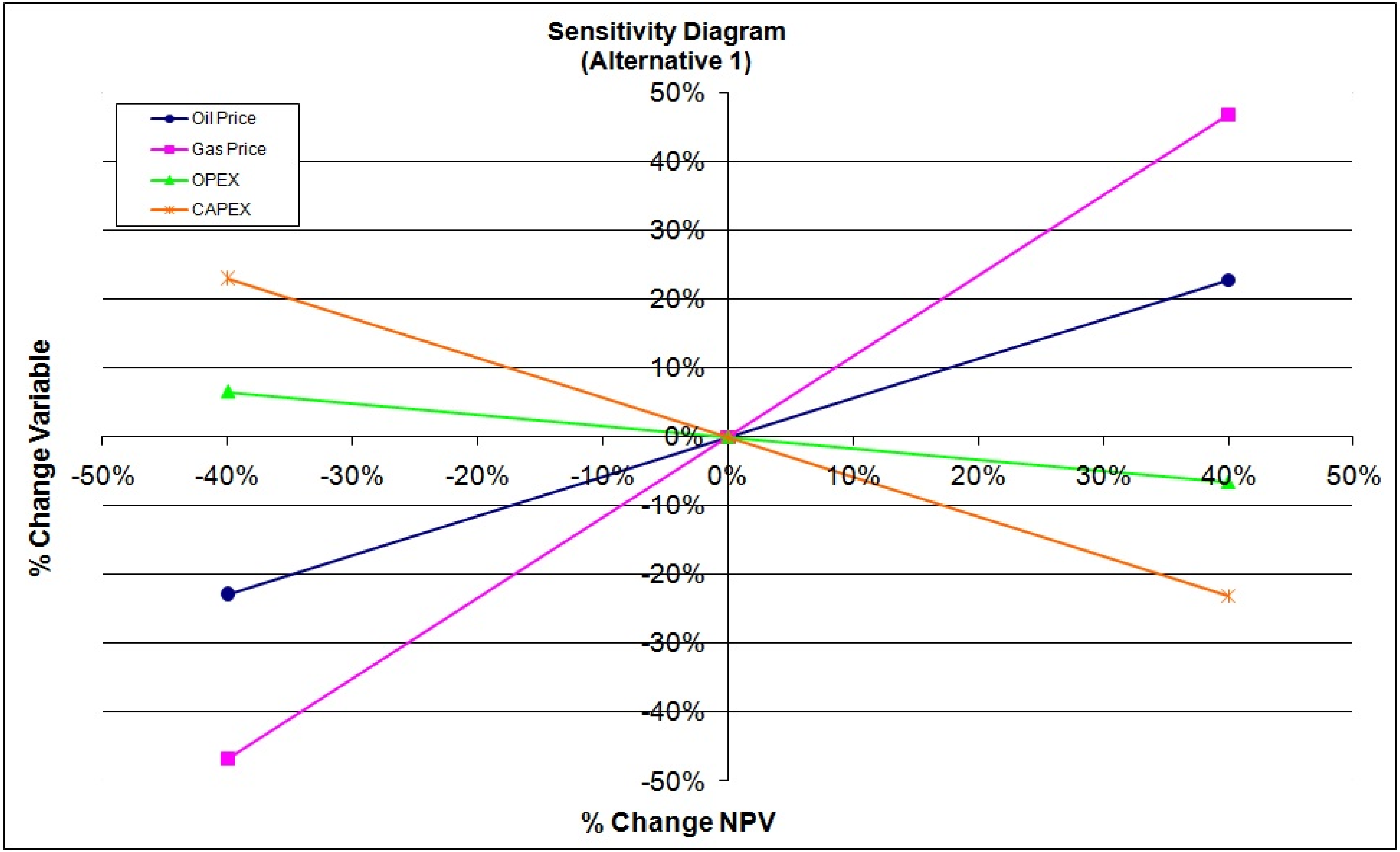

Sensitivity Diagram
(Alternative 1)
Oil Price
Gas Price
OPEX
CAPEX
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-40%
-50%
-50%
-40%
-30%
-20%
-10%
0%
10%
20%
30%
40%
50%
% Change Variable
% Change NPV

Figure 3.6

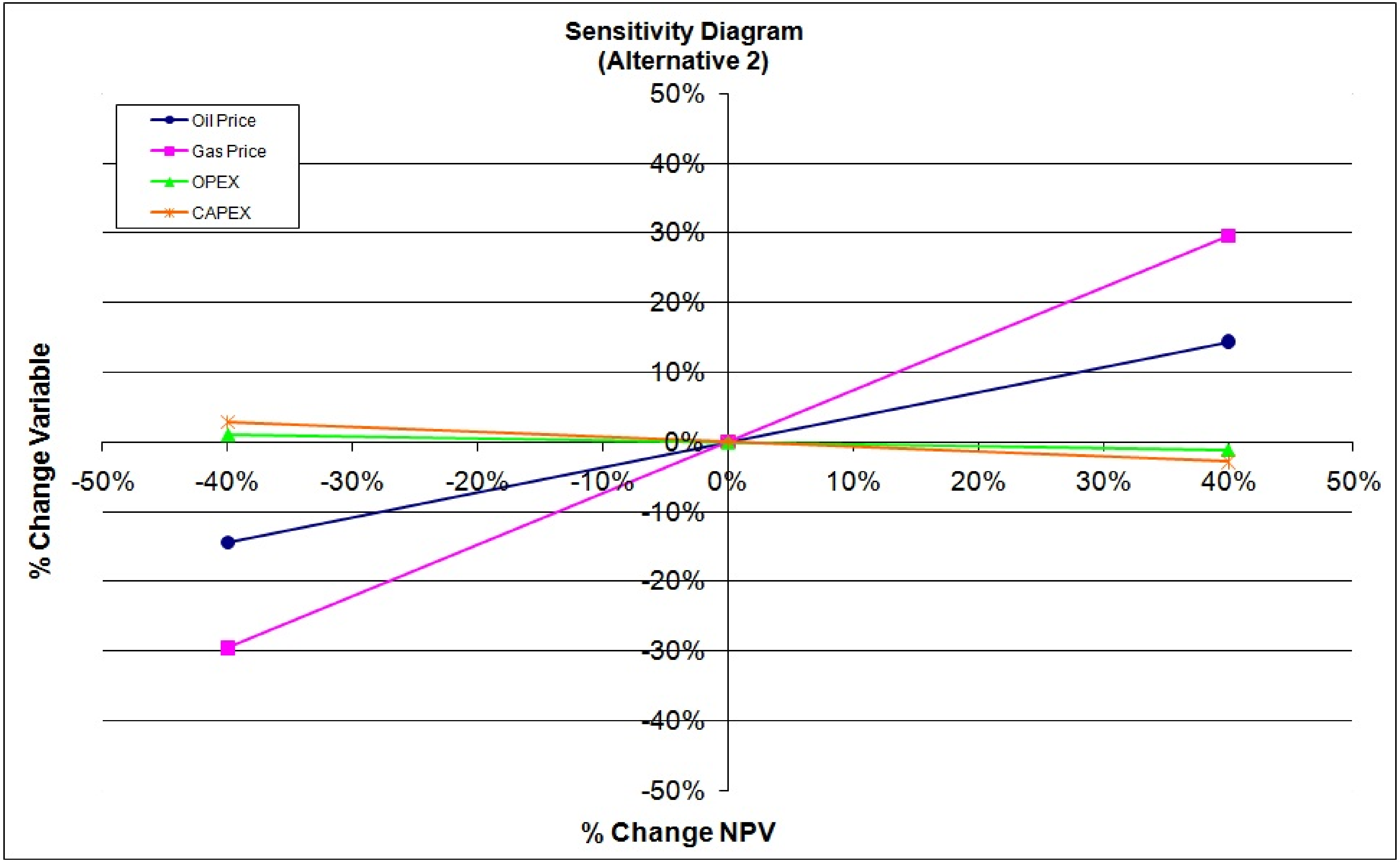

Sensitivity Diagram
(Alternative 2)
Oil Price
Gas Price
OPEX
CAPEX
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-40%
-50%
-50%
-40%
-30%
-20%
-10%
0%
10%
20%
30%
40%
50%
% Change Variable
% Change NPV

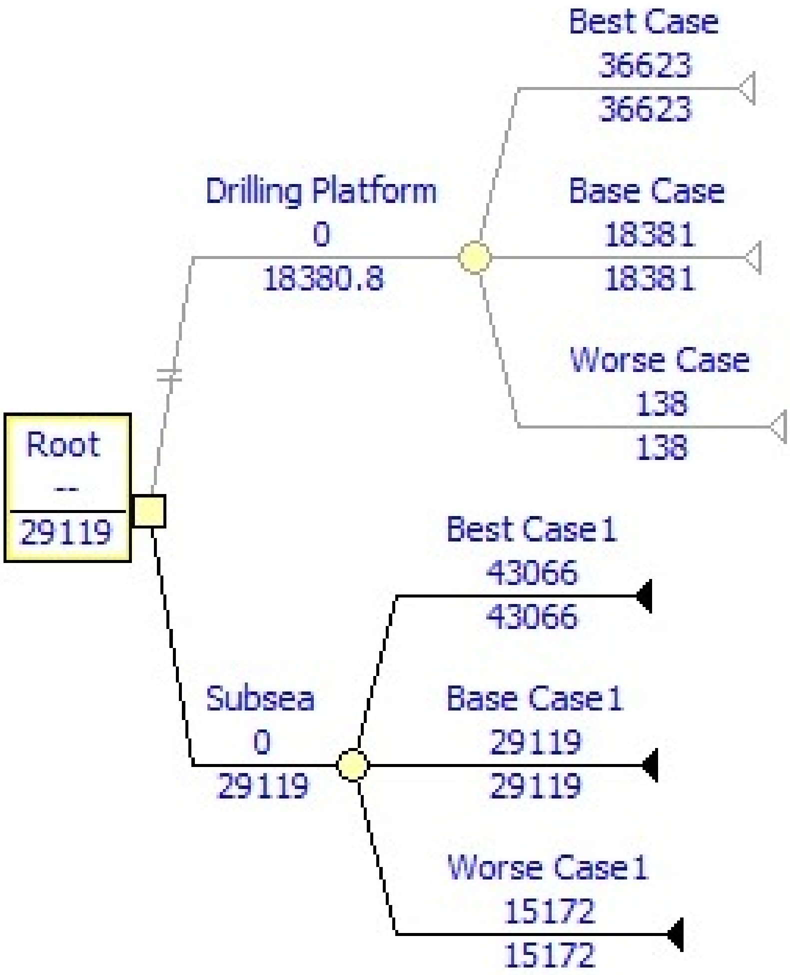
Figure 3.7

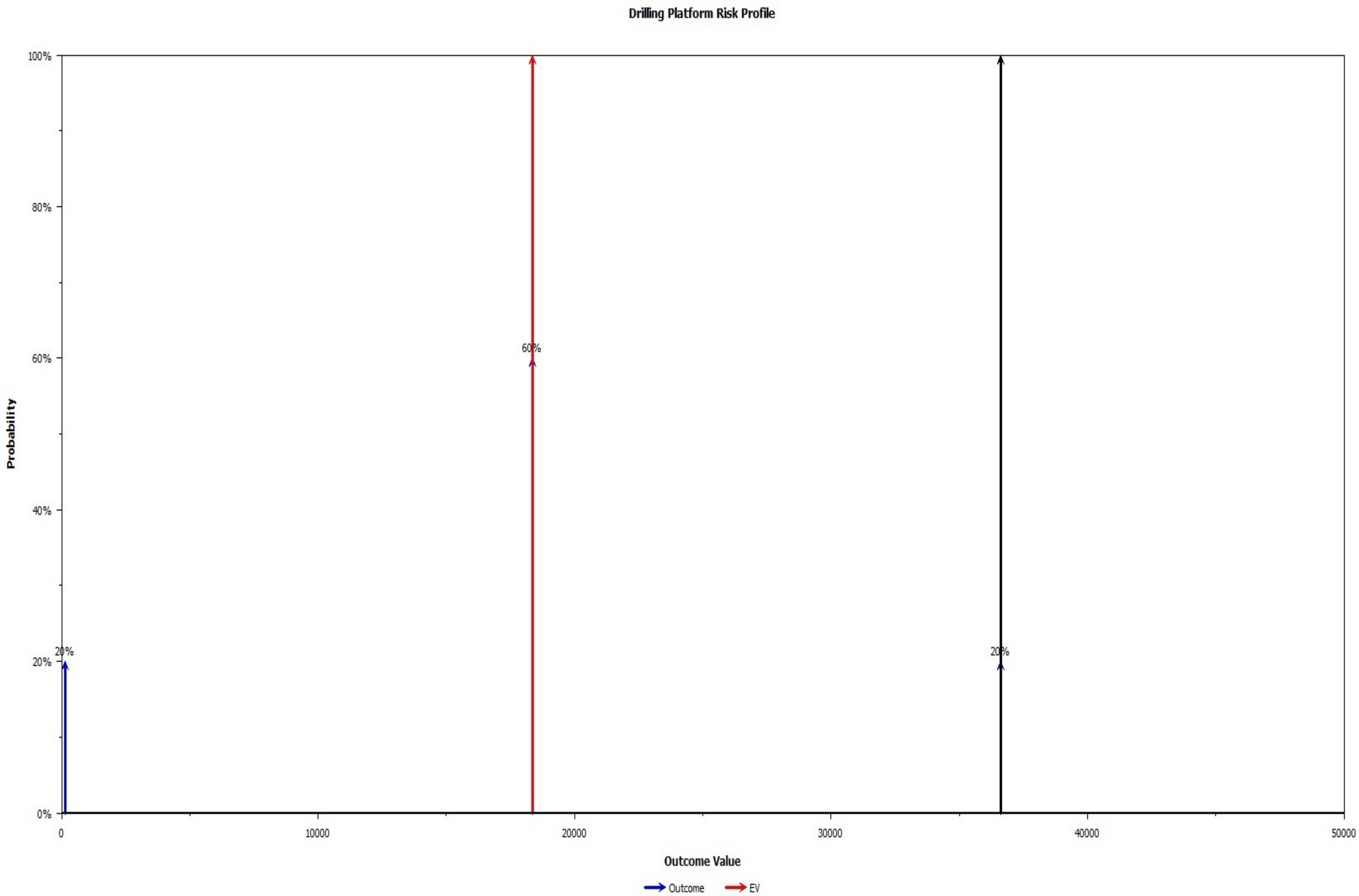
As it is shown in figure 3.6, for alternative1, the total NPV is sensitive more by Gas price, CAPEX cost, Oil price and at last by OPEX cost respectively.

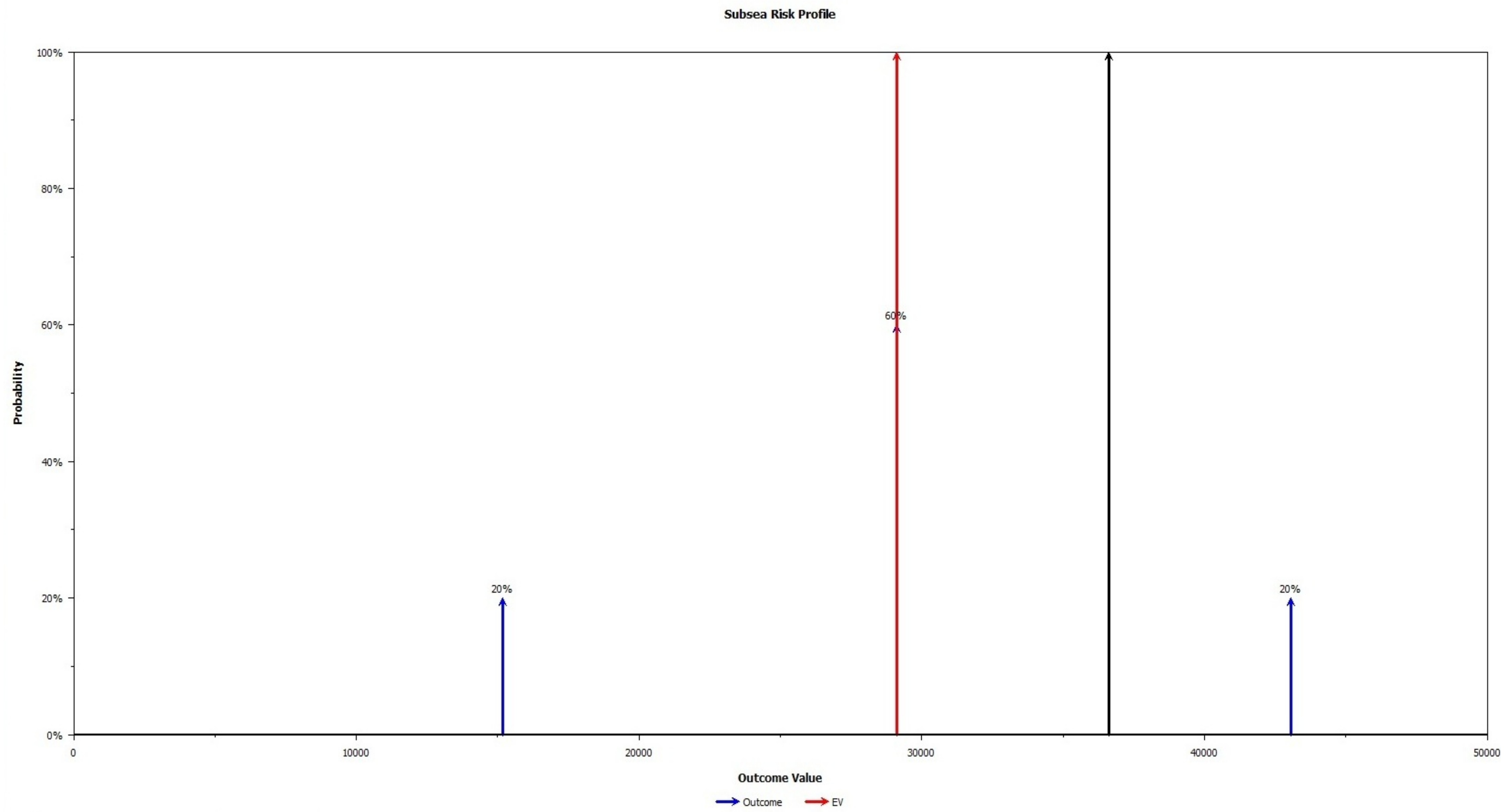
And for alternative 2, as it is shown in figure 4.6, the total NPV is sensitive more by Gas price, Oil price, CAPEX cost and at last by OPEX cost respectively.

In comparison between alternative 1 and 2, the percentage of total NPV sensitivity by these four variables in alternative 2 is considerably less rather than alternative 1.

3.6 Decision Tree:




Drilling Platform Risk Profile
100%
80%
60%
40%
20%
0%
Probability
60%
20%
20%
0
10000
20000
30000
40000
50000
Outcome Value
Outcome
EV



In conclusion, we could say that by the mentioned assumption, choosing alternative 2 of extended case will be economical in all three possible cases that during the project might be happen. Though, the most likely case is the base case with 60% probability.

References

1) *INGRID DRANGE (2003)* Analyse av seismisk data innenfor Gullfakslisensen – implikasjoner for tolkningen av topp Ner

2) *STATOIL (2003)* Reservoarstyringsplan for gullfaks hovedfelt og satelitter 2003 – Årlig statusrapport

3) *STATOIL (2004)* Reservoarstyringsplan for gullfaks hovedfelt og satelitter 2004 – Årlig statusrapport

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5) www.statoil.com

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